On the Technical and Economic Feasibility of Remote Area Hydrocarbon Exploitation Using Offshore Electrical Power Generation and Transmission
(Clean Energy Producing Vessel)

by

Eng Hwa Yap

A thesis submitted in partial fulfilment of the requirements for the degree of
Doctor of Philosophy

University College London

2008

Statement of Originality

I confirm that the work presented in this thesis is my own and where information has been derived from other sources this has been duly referenced. The contributions to knowledge I claim to have made in the subject area of marine engineering are as follows:

1. A comprehensive literature and patent review in the area of offshore electrical power generation and transmission has been conducted to understand the state-of-the-art. Together with a review of future UK energy needs this has resulted in the novel Clean Energy Producing Vessel (CEPV) concept being proposed.

2. Technical feasibility of the CEPV has been investigated in detail by considering the natural gas processing plant, electricity generating plant, exhaust treatment plant, CO_2 sequestration plant and subsea transmission system with particular focus on the design of a Base Case CEPV.

3. A design for the CEPV has been achieved by giving consideration to its specific technical requirements and unique role which resulted in a conceptual design of a CEPV - FPSO type vessel.

4. A computer based model for calculation of fatigue and prediction of fatigue life of cable riser (a unique requirement for the CEPV) has been established. The performance of cable riser under different sea states is presented.

5. An economic performance analysis of the Base Case CEPV has been carried out. This was achieved using an Economic Model to establish performance indicators and variations with different CEPV solutions. This analysis has included case studies.

Abstract

In this thesis the author's research into the technical and economic feasibility of exploiting remote hydrocarbon reserves using Clean Energy Producing Vessel (CEPV) is documented.

An opportunity for the CEPV arises because of several concurring issues; the demise of UK North Sea offshore oil and gas industry; residual gas reserves remaining in small pocket fields in the North Sea and elsewhere which are unconnected by gas pipeline; concern over the energy gap in the UK electricity market; and recent developments and knowledge in offshore electrical generation and transmission technologies for the offshore industry, primarily developed for the renewable sector.

This research programme had three key challenges. Firstly, the concept of CEPV had to be firmly established by considering the current state of the UK electricity supply and demand picture; the location, quality and quantity of fuel (primarily natural gas). This research undertaken by literature review led to the specification of the plant itself including identifying appropriate technologies required both offshore and onshore.

Secondly, the technological issues were examined in detail including; the requirement of a natural gas processing plant to extract valuable condensates; the design of an offshore power station with the technological prime-mover options and solutions; the generation and transmission of the electrical power; and the feasibility of using CO_2 sequestration. Further consideration was given to the design requirements of an appropriate vessel to house the offshore power station. The approach taken was to examine the technical issues in depth by examining the 'state of the art' then selecting an appropriate solution that met the requirements and identifying particular issues such as cable riser design in greater detail.

The third challenge was to assess the economic feasibility of the CEPV. The approach taken was to assess the economics of different scenarios and by making comparisons with a base case model using a discounted cash flow (DCF) model, in which an iterative solution set up to find the internal rate of return (IRR) of the project is used. This analytical method gave the predicted cost of a unit of electricity, which could then be compared against those prices charged by other electicity generators. The thesis as presented is believed to be an original idea and is considered to contribute to the expanding discussions on offshore power generation schemes. The novel contribution is by way of the specification and lies in the technical design and subsequent analysis of the CEPV.

Marine Engineering –

An engineering science that is broad through necessity

and deep where necessary

This work is dedicated to Papa, Mummy and Hoe...

... for their unwavering love, unfaltering support and immense patience.

Table of Contents

List of Figures

List of Tables

Acknowledgments

The author wishes to express sincere appreciation to his Principal Supervisor Dr Richard Bucknall for his unconditional support and excellent guidance throughout the duration of his research at UCL; Eur Ing David Fellows for acting as Secondary Supervisor; Mr Konrad Yearwood and Dr Sharon Cheang for their advice and assistance in the preparation of this thesis.

The author also wishes to acknowledge the financial assistance of the Department of Mechanical Engineering at UCL in the form of Research Studentship (BG Group, BP and Shell JIP); IMarEST in the form of Stanley Gray Fellowship Award; and Rolls-Royce in the form of CESA Smart Award.

The author also acknowledges the kind assistance from former members of the Offshore Power Group Dr Hugh Martindale when developing the Economic Model; and naval architects Mr Ekanum Etuk and Mr Haruna Umaru-Mohammad when analysing the naval architecture aspects of the CEPV design.

Special thanks to Dr and Mrs Konrad Ciaramella, Dr Chang-Hsin Chien, Dr Chee Kuang Tam, soon-to-be Dr Alexander Karyotakis, Mr John Inns and other members of Team Solarfox (www.teamsolarfox.com) for their friendship and inspiration – "Go! Go! Go!" – without their enthusiasm this doctorate would have been impossible.

Last but not least, the author is immensely grateful to his family and many good friends for their affection and encouragement over all these years.

Nomenclature

α = helix angle

β_i = the lay angle of the strips in layer I

θ = angle of the tangent to the cable makes with the horizontal

θ_0 = angle that the cable makes with the seabed

ν = Poisson ratio

φ = the twisting of the core in the rotation per unit length

ρ = density

σ_b = bending stress

τ_0 = the dynamic tension in the cable

ω = wave frequency

Ω = reduced frequency

$\frac{d\theta}{ds}(s) = x$ = static catenary curvature

g = acceleration due to gravity

h = water depth

l = suspended length of the cable

l_i = length of one wrap in layer (i)

m = number of armouring layers

n_i = number of strips in the layer

w = weight per unit length of the cable

w_{eff} = the effective weight per unit length

A = cross sectional area of the armouring strip

A_{ci} = cross sectional area of material ith of the core

C_D = drag coefficient

Cm = Machinery Cost

Cs = Steel Cost

D = external diameter of cable

E = modulus of elasticity

E_b = modulus of elasticity of the bth layer of material

$EA_{effective}$ = effective Axial Stiffness

$E_c A_c$ = axial stiffness of the core and or n layer of materials with different elastic

E_{ci} = elastic modulus of material ith of the core

EI = effective bending stiffness of the cable

E_i = modulus of elasticity of material i

K = the distributed shear stiffness that gives the measure of the friction factor

L_i = length of the core equivalent to one wrap length l_i

MW_{GT} = Gas Turbine Power

MW_{ST} = Steam Turbine Power

N_{GT} = Number of Gas Turbine

N_{ST} = Number of Steam Turbine Power

NPV = Net Present Value

R = radius of individual wire

R_i = pitch radius of the strip in layer i

S = curve linear coordinate

T(s) = axial tension along the length of the cable

$T_0(s) =$ static tension in the cable

Tc_i = tension taken up by material ith of the core

TDP = touch down point

TE = top end

Q = Effective weight of cable in water.

V = shearing force

X_{TDP} = Location of Touch Down Point

Ws = Steel Weight

Wo = Outfit Weight

Abbreviations

AC Alternating Current

AGR Advanced Gas-cooled Reactor

bbl Barrel

BETTA British Electricity Trading and Transmission Arrangements

CACW Closed Air Cooling Water

CAPEX Capital Expenditure

CCGT Combined Cycle Gas Turbine

CHP Combined Heat and Power

CO_2 Carbon Dioxide

CPI Consumer Price Index

DC Direct Current

DCF Discounted Cash Flow

DEA Diethanol Amine

DLE Dry Low Emission

DP Dynamic Positioning

DTi Department of Trade and Industry

EC European Community

EOR Enhanced Oil Recovery

EPCS Engineering, Procurement, Construction and Supervision

FBC Fluidised Bed Combustion

FPSO Floating Production Storage and Offloading

HC Hydrocarbon

HMRC HM Revenue and Custom

HP High Pressure

HVAC High Voltage Alternating Current

HVDC High Voltage Direct Current

ICR Integrated Conductor Cable

I-C-R Intercooler-Recuperator Gas Turbine

ID Inside Diameter

IRR Internal Rate of Return

LNG Liquefied Natural Gas

LP Low Pressure

MEA Monoethanol Amine

MIND Mass Impregnated Non Draining

MJ Mega-Joule

mmscf/d Million Standard Cubic Feet per Day

MW Mega Watt

MWe Mega Watt Electric

MWh Mega Watt Hour

NFP Near Far Point

NG Natural Gas

NLNG Nigeria LNG Ltd.

NNP Near Near Point

NPV Net Present Value

OD Outside Diameter

OPEX Operational Expenditure

PP Payback Period

PV Present Value

SBP Standard Buying Price

SS Sea State

SSP Standard Selling Price

STIG STeam Injected Gas Turbine

STP Standard Ambient Temperature and Pressure

STP Submerged Turret Production

TDP Touch Down Point

TE Top Eng

TLC Through Life Cost

TLP Tension Leg Platform

TWh Terra Watt Hour

UPC Unit Production Cost

VSC Voltage Source Converter

VSI Voltage Source Inverter

WHRU Waste Heat Recovery Unit

XLPE Cross Linked Polyethylene

Definitions

CAPEX (Capital Expenditure) The sum of capital needed at the beginning of year one (end of year zero) to facilitate the CEPV project.

IRR (Internal Rate of Return) The annualised effective compounded rate of return which can be earned on the investment of capital or, in other words, the yield on the investment.

NPV(Net Present Value) The standard method for the financial appraisal of long term projects that measures excess or shortfall of cash flows, in present terms, once financial charges are met.

OPEX (Operational Expenditure) The annual costs of operating the CEPV at the chosen location and includes manning costs, maintenance costs, provisioning costs and consumable costs.

PP (Payback Period) The period of time required for the return on an investment to repay the sum of the initial investment when OPEX is accounted for.

Revenue The monies received from the sale of the generated electricity and the sale of condensate. Revenue is time dependent.

1 Introduction

1.1 Background and Motivation

Energy has always been important but today it is essential in our daily lives and it is a fundamental requirement for man's continued prosperity. The Industrial Revolution, which began in the UK in the 18th Century, saw the beginning of a surge in demand for energy, as a consequence of advancements in industrial manufacturing, which has continued to the present day. Figure 1 shows the growth of world energy demand over the past century and the predicted demand for the next half century.

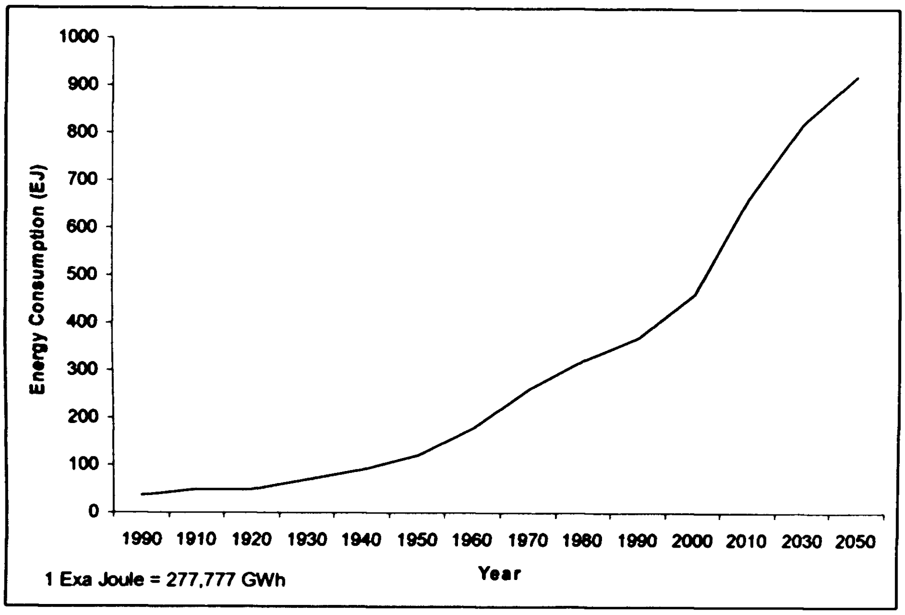


Figure 1 World Energy Consumption[1]

Figure 2 shows the total energy consumption by sector in the UK whilst Figure 3 shows total electricity consumption in the UK in 2007. Electricity represents 19 % of the total energy demand. Electricity demand is predominantly from transport (39 %), domestic (28 %) and industry (20 %). Figure 4 shows how demand for electricity in the UK has continued to increase year on year and how generation capacity is being maintained marginally above demand levels.

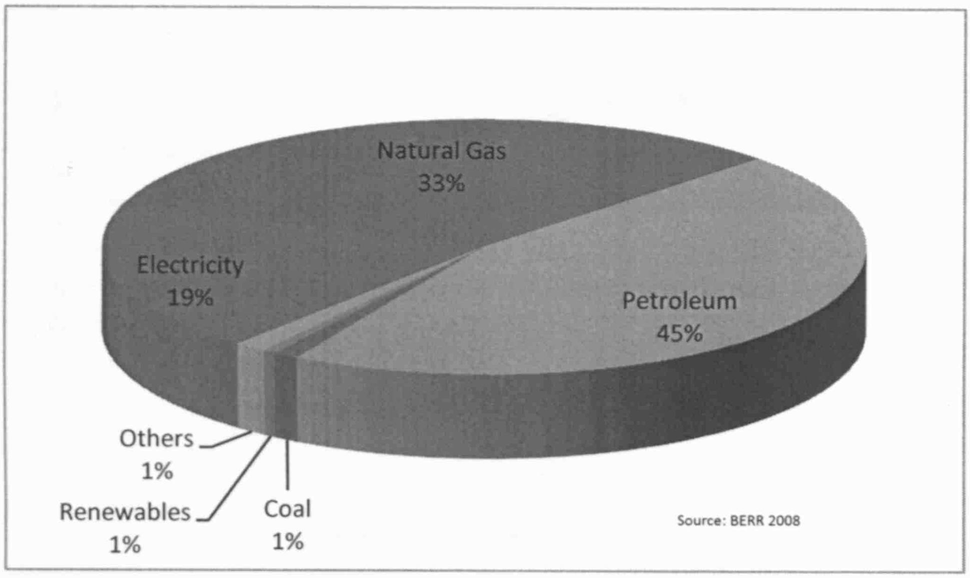


Figure 2 Energy Consumption by Sector in the UK 2007 (Data from BERR)[2]

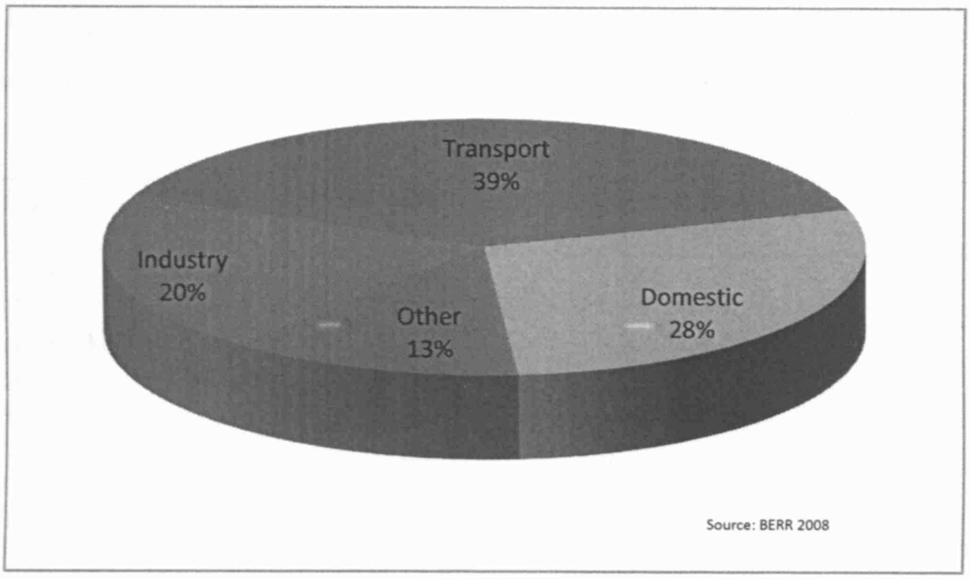


Figure 3 Electricity Consumption in the UK 2007 (Data from BERR)[2]

Despite activities to reduce demand, it is projected that there will be a shortfall of electrical power generation capacity in the UK arising over the next twenty years[3] as older power stations, particularly coal fired and nuclear power stations, are taken out of service. At the same time there is increased governmental pressure to reduce CO_2 emissions by some 60 % by 2050, with real progress in sight by 2020[9].

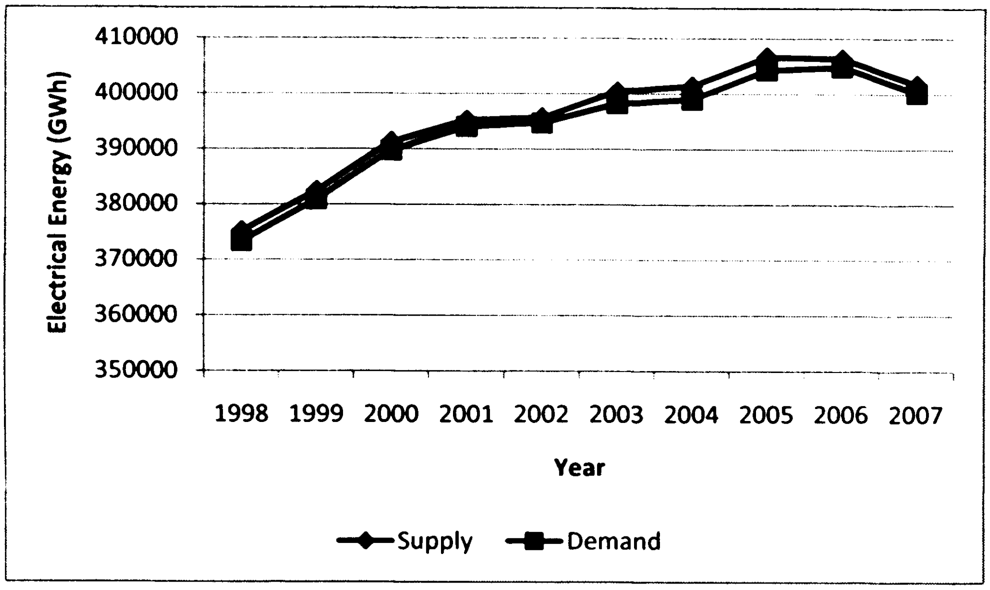


Figure 4 Total Electricity Supply vs. Demand 2007 (Data from BERR)[2]

Figure 5 shows the total electricity production in the UK in 2007 whilst Table 1 shows the changes in primary energy sources for generating electricity between 1990 and 2007.

Table 1 Total Electricity Production in 2007 and 1990 (Data from BERR)[2]

Type	*Production in 2007 (TWh)*	*%*	*Production in 1990 (TWh)*	*%*
Coal	382.6	39.0	579.6	65.3
Oil	14.2	1.4	97.7	11.0
Natural Gas	353.0	36.0	6.5	0.7
Nuclear	163.3	16.7	189.1	21.3
Hydro	5.1	0.5	5.1	0.6
Wind	5.2	0.5	0	0.0
Other	56.8	5.8	9.8	1.1
Total	980.2	100	887.8	100

In 1990, coal fired power stations and nuclear power stations dominated the electricity generating industry. In 2007, coal fired power stations, although significantly reduced, still dominate electricity generation despite a growth in nuclear power, gas fired power stations and renewable energy predominantly wind and hydroelectric schemes. Wind power generation came into the picture in the mid 1990s and continues to grow so that renewable energy sources account for 4.3 % of electricity generation[4].

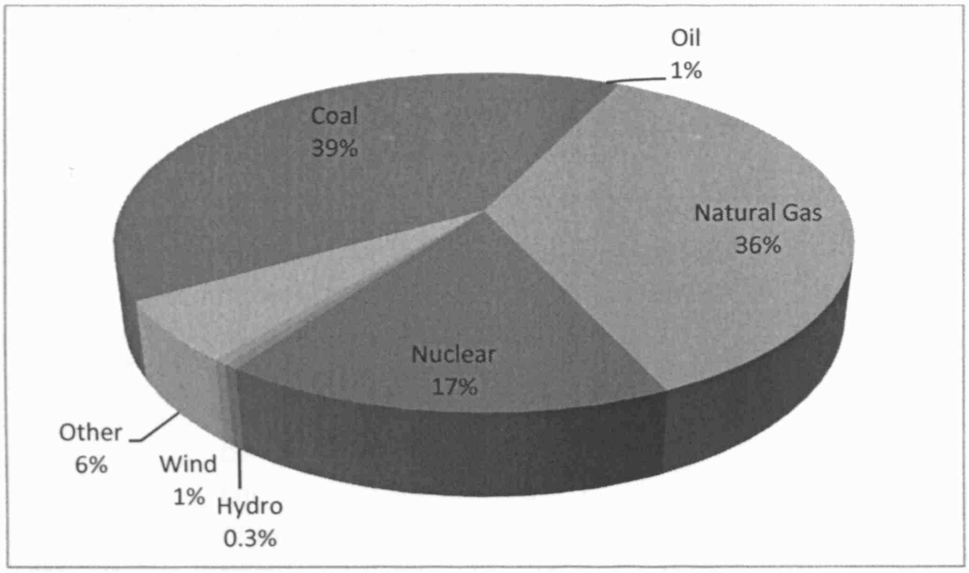


Figure 5 Total Electricity Production 2007 (Data from BERR)[2]

It is apparent from the above that in 2007 hydrocarbon fuel sources provide 75 % of the electricity demand. A CO_2 emissions reduction by 60 %, as proposed by the UK government[9], would need to see either a significant increase in the use of renewable energy sources or an increase in the use of nuclear energy by some 78 %, or the development of a new 'carbon free' electricity generating technology such as nuclear fusion5.

1.2 Regulatory Policy Addressing Future Electricity Needs

At the beginning of the 21st century, concerns began to surface over the prospect of an 'energy gap' in the UK's generating capacity. Concerns were initially raised in a report published in 2000 by the Royal Commission on Environment Pollution (Energy - The Changing Climate)[6]. This concern arose because it was expected that a number of coal-fired power stations will be shut down, owing to them being unable to meet the clean air requirements for the European Large Combustion Plant Directive (Directive 2001/80/EC)[7] and the fact that the majority of these power stations are at the end of their lives, as demonstrated in Table 2. In addition, the UK's four remaining Magnox nuclear stations and four of the seven Advanced Gas-cooled Reactor (AGR) nuclear stations are expected to close by 2015[17]. The 'energy gap' concern has partly been offset by extending the lives of some AGR nuclear power stations and by investment in new generating capacity e.g. new gas fired power stations, CHP plants and renewable energy[8].

Table 2 Power Stations over 30 Years Old in the UK 2007 (Data from BERR)

Type	*No. of Stations*	*No. of Stations Over 30 Years Old*	*%*
Gas	26	10	38.5
Coal	18	15	83.3
Nuclear	10	4	40
Wind	94	0	0
Hydro	78	67	85.9
CCGT	32	0	0
Oil	3	1	33.3
CHP	5	0	0
Other	24	12	50
Total	290	109	37.6

More recently, the government published the Energy Review 2006[9] which attracted considerable press coverage, in particular in relation to the prospect of constructing a new generation of nuclear power stations to eliminate CO_2 emissions that would have been exhausted if conventional power stations were built instead. In 2007, the government reaffirmed its support for low and zero CO_2 emission power stations by supporting nuclear energy and renewable energy in the Energy White Paper published in 2007[10].

The Energy Review 2006 highlighted two challenges that the UK will face in the future; climate change and security of energy supplies. Climate change, which is thought to be caused by the build-up of CO_2 and other greenhouse gasses in the atmosphere, is partly attributed to emissions from power stations. The UK Government has committed to the obligations of the Kyoto Protocol[11] to reduce the levels of CO_2 and other greenhouse gas emissions to 12.5% below the 1990 levels over the period 2008 to 2010.

Achieving the Kyoto Protocol targets has been made easier due to a reduction of CO_2 emissions caused by the displacement of coal by natural gas for electricity generating capacity. However the UK, which has been self-sufficient in natural gas, using stable supplies from North Sea, is now experiencing a waning of natural gas reserves and, in the future, the UK will increasingly depend upon natural gas imports to meet demand and is therefore set to become a net energy importer by 2010[12].

1.3 Electricity Generation in the UK

In the following paragraphs a review of each of these power station types is given with reference to the desire to reduce CO_2 and to maintain security of supply.

1.3.1 Coal

In the 1990s, the emergences of natural gas as a primary fuel for electricity generation meant that coal fired power stations were gradually displaced. This displacement was primarily encouraged by the availability of cheap natural gas from the North Sea throughout the 1990s[13]. By 2007, eighteen coal fired power stations were in operation contributing 39 % (382.6 TWh) of the UK's total electricity production.

The usage of coal can be expected to decline steadily because of mounting pressure to reduce CO_2 emissions. The Energy White Paper, published in 2007, stated that in order to preserve a diverse energy mix, the UK should continue to generate electricity using coal fired power stations but that these power stations should continue to reduce sulphur and CO_2 emissions. The eminent closure of old 'dirty' coal fired power stations over the next few years is likely to encourage investment in 'clean coal' technology. One of the methods is Fluidised Bed Combustion (FBC) where the coal is burned in a reactor comprised of a bed through which natural gas is fed to keep the fuel in a turbulent state. FBC has the potential to reduce SO_x and NO_x emissions by some 90%[14]. The UK does not need to rely upon imported coal as it has its own considerable coal reserves.

1.3.2 Gas

The consumption of natural gas in the UK has seen rapid expansion in industrial, domestic and service sectors. Since the 1990s the growth in natural gas consumption has been dominated by its increasing use for electricity generation, which now accounts for some 30 % of natural gas consumption[2]. By 2007, there were 26 gas fired power stations and the electricity generated from natural gas accounted for 36 % (353 TWh) of the UK's total demand[2].

Natural gas is likely to play a part in the UK's future energy needs. As production from the North Sea continues to decrease, efforts have been stepped up to expand and enhance pipelines and storage facilities of imported natural gas using LNG tankers and via underwater pipelines with imported natural gas from Norway (Langelad) and Russia[15]. At the same time there is a realisation by the UK government of its vulnerability when relying upon imported natural gas[3].

1.3.3 Nuclear

Nuclear power is a resource to provide clean electricity[16]. Without a contribution from nuclear power, the UK's CO_2 emissions would have been 5 to 12 % higher in 2004[17]. In 2007 the total number of commercial nuclear power stations in operation in the UK was 10, with an installed capacity of 11,800 MW[18]. This capacity provided 16.7 % (163.3 TWh) of the UK's total electricity production. The publication of The Energy White Paper 2003 left open the future of nuclear power in the UK. Since then several developments, including increasing evidence of climate change, new technologies in managing legacy nuclear waste, greater than expected increase in fossil fuel prices, and keen interests from investors in nuclear power seems to have changed government and public perception towards nuclear power. This has led to renewed interests in nuclear power to address the UK's two key policy goals; reducing CO_2 emissions and security of energy supply, as laid out in The Energy Review published in 2006 and the Energy White Paper published in 2007. Despite the UK Government's decision in January 2008 to support the building of new generation nuclear power plants, the Scottish Government is opposed to building nuclear power plants in Scotland[19].

The 'half life' is an important factor when dealing with nuclear waste. The half-life of a nuclear waste is inversely related to the intensity of radioactivity of an isotope[20]. Isotopes with a long half-life decay at slower speed and producing fewer radioactive decays per second, therefore their intensity is less whilst isotopes with shorter half-lives are more intense[20]. In addressing the concerns of the security of nuclear waste, the effect of its half life, storage and protection for future generations have to be ensured.

Whilst nuclear fusion power has the potential to produce 'safer' energy more efficiently[21]; it is still in its experimental stage. Nuclear power does not produce CO_2 when generating electricity (although the construction and decommissioning of nuclear power plant, mining, waste handling and disposal does generate CO_2)[22], but it does raise other environmental and security concerns. If the economics of nuclear power can be addressed then nuclear power's ability to generate large amounts of inexpensive 'clean' electricity is indeed a very attractive solution.

1.3.4 Wind

In the UK wind generation is rapidly growing. In 2006, the British Wind Energy Association forecast that onshore wind farms are likely to supply approximately 5% of the national electricity requirements by 2010[23]. In 2007, there were a total of 94 wind farms providing 0.5 % (5.2 TWh) of the UK's total electricity production.

Whilst the potential for wind energy is huge and the growth is promising, there are a number of problems. Onshore wind farms have grown considerably over the past ten years (approximately six fold) but many Planning Applications for onshore wind farms are objected to for domestic and environmental reasons e.g. Guestwick wind farm in Norfolk which has been rejected three times[24]. Also, total dependence on wind would require an energy storage system or a spinning reserve to overcome fluctuations in wind energy to ensure integrity of supply[25]. For offshore wind farms high power transmission systems are needed to transmit the generated electricity to shore and such subsea cables can be a high proportion of the cost primarily because wind turbines are typically rated between 2 and 4 MW and require interconnecting cables and cables connecting the wind farms to shore[26]. This affects the economic feasibility, particularly for small offshore wind farms. Furthermore investment in wind farms has generally been weak but recent renewed commitment from the government, investors, regulators, infrastructure providers (National Grid) and the scientific community alongside a strengthened framework in realising the UK's Renewables Obligation[27], the future for wind energy, particularly offshore wind, is now more promising.

1.3.5 Hydroelectric

Globally hydroelectric power remains the largest form of renewable energy. The World Energy Council reported that at present, hydroelectric power provides 19 % (1,650 TWh/year) of world's energy supply[28]. Unfortunately, large hydroelectric schemes are seen as being unfavourable for ecological and socio-economic reasons[29]. In the UK hydroelectric schemes contribute only 1% of the total electricity production as shown in Figure 5, and there is little opportunity for increasing the number of such schemes.

1.3.6 Wave

The UK is surrounded by water and this makes it ideal for generating electricity from wave, tidal and current renewable power sources. However, these have received little funding for development and consequently have not yet been exploited on a significant commercial basis, although funding for Scotland's 'Pelamis' wave farm and the 'Wave Hub' offshore Cornwall was approved in 2007[30].

Due to their present generating capacity, wave and other marine generation are considered to be undeveloped. It is unforeseeable that they can contribute significantly towards the UK's electricity generating capacity in the near term and in the longer term their roles are difficult to predict.

1.4 The Future of Electricity Generation in the UK

The emphasis now and in the future is to introduce new and 'cleaner' electricity generating capacity where the risks associated with the security of supply are mitigated. Fossil fuel power stations can only contribute to the solution if there is an economic and a sustainable way of reducing CO_2 emissions such as by using CO_2 sequestration. Nuclear power does not emit CO_2 but there are environmental and security concerns over the handling and disposal of radioactive waste. Onshore and offshore wind energy presents a huge potential for supplying clean and sustainable energy. The potential for generating large amount of renewable energy using hydroelectric generations are huge because its power density is high. For example, tidal barrages across the Severn Estuary and the River Mersey have the potential to harvest significant amounts of renewable energy by generating in excess of 6% of the electricity demand for England and Wale[31] but the environmental implications for local ecosystems are thought to be detrimental[32]. Other generating methods such as co-generations e.g. CHP, the use of bio-fuels, solar and micro-generation provide promising avenues, these have yet to be explored on a commercial scale so as to become a significant and dependable electricity supply.

1.5 Clean Energy Producing Vessel

A new electricity generating technology solution, proposed by the author, is the exploitation of abandoned small sized natural gas reserves in the North Sea using a Clean Energy Producing Vessel (CEPV). The concept can be seen in Figure 6. The CEPV is a floating power station which generates electricity using natural gas that lies abandoned in many small offshore fields simply because a pipeline to shore is uneconomic. The CEPV exports the generated electricity to shore via a subsea electricity transmission cable to the National Grid. The CO_2 emissions from the CEPV's electricity generating plant are sequestrated into one of the many larger abandoned oil and gas fields in the North Sea. Additional features of the CEPV include its ability to be moved from one generating site (gas field) to another and its ability to reuse the same transmission cable.

The CEPV solution overcomes the limited power that is obtainable from individual generators that exploit renewable energy resources such as wind, wave and current, and it avoids dependence upon unpredictable natural resource behaviour. It also overcomes the high costs associated with new nuclear power stations and it also avoids emissions from shore based hydrocarbon generators, none of which currently use CO_2 sequestration. The CEPV has the potential to generate significant quantities of 'clean' electricity at the time it is needed.

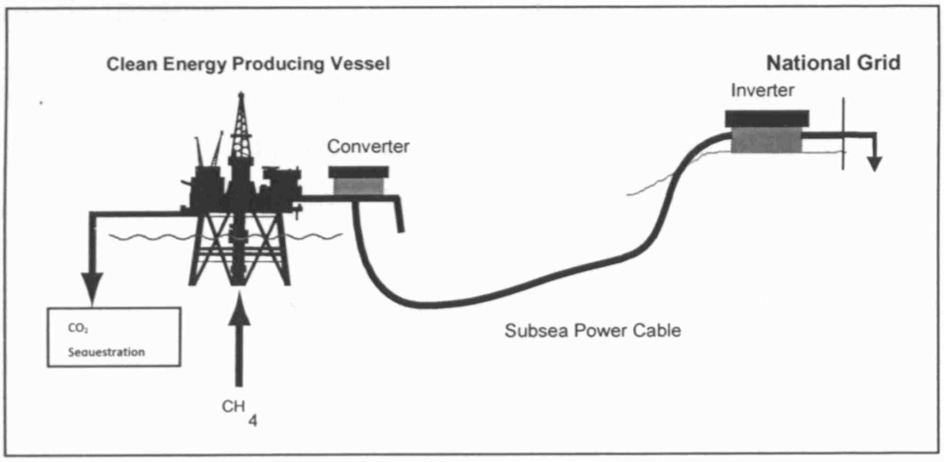


Figure 6 Clean Energy Producing Vessel (CEPV) Concept

This thesis set out to investigate this novel concept in detail. The work involved has considered both the technical and economic feasibility of the CEPV.

1.6 Research Aims

The aims of the research reported in this thesis are to address the following key challenges for the CEPV concept:

- To undertake a literature search to establish the originality of the concept proposed and to extend the literature review into related technical areas including natural gas processing, electricity generating plant, CO_2 sequestration and vessel design.

- To establish whether appropriate natural gas reserves are available for exploitation by the CEPV and to establish whether appropriate abandoned fields are available for CO_2 sequestration.
- To conceptually design a CEPV that is technically and economically achievable. The CEPV must be capable of importing natural gas and exporting electricity to market and CO_2 for sequestration.

- To assess the economic feasibility of the CEPV by establishing a 'Base Case CEPV' for a defined field scenario and then to establish the impact of variations of the design on the CEPV's performance with specific reference to real case studies.

1.7 Thesis Outline

This thesis consists of eight chapters. In each chapter there is an introduction which establishes the chapter objectives and a review of related work to support each investigation. There is also a summary which addresses the findings in each chapter.

Chapter One covers the background to the research investigation. Electricity generation in the UK is reviewed and the CEPV concept is introduced. The research aims are established and an outline of the thesis is presented. The important aspect of this chapter is the identification of a niche research area.

Chapter Two considers the CEPV in more detail. The chapter begins by reviewing the literature and patent databases to establish whether any similar concepts have been previously proposed. The major technological areas including the generation of electricity offshore, natural gas processing, subsea transmission and CO_2 sequestration are considered in outline. The important aspect of this chapter is to identify the key technologies and economic issues that need to be addressed in greater depth in the following chapters.

Chapter Three considers three key technology areas; the natural gas processing plant, electricity generating methods, and the CO_2 sequestration pant. This chapter focuses on gas flow issues by considering the flow of natural gas from the field, the processing requirements to provide a suitable fuel for the prime-movers, exhaust gas processing to allow its preparation for CO_2 sequestration, and the CO_2 sequestration plant. The important aspect of this chapter is to establish an understanding of the relationships between the various stages of the process from a gas flow perspective.

Chapter Four considers electricity generation and its transmission to shore using a subsea cable. The focus of this chapter is to establish appropriate equipment and methods that will allow successful transmission of electricity from the CEPV to the National Grid. The important aspect of this chapter is to establish an understanding of the alternative means that are available to export electricity from the CEPV, and when and how each method should be used.

Chapter Five reports on a conceptual design undertaken to establish a specific vessel that can house the technologies required by the CEPV and the ancillary services needed by the vessel and its crew. The focus of this chapter is to ensure that the CEPV concept is technically feasible since all the technologies must be brought together within one single vessel. The important aspect of this chapter is to establish whether or not the CEPV is a realistic technical proposition.

In Chapter Six the design and development of an Economic Model for the CEPV is presented together with results from an economic evaluation of a Base Case CEPV scenario. The Economic Model, which is a discounted cash flow (DCF) model, is based upon Net Present Value (NPV) and it primarily establishes Capital Expenditure (CAPEX), Operational Expenditure (OPEX), Internal Rate of Return (IRR) and Payback Period (PP) achievable for a specified CEPV design and gas field scenario.

Chapter Seven is concerned with sensitivity analyses by using the Economic Model to examine the effect of changes in financial conditions, the CEPV technical specification, and the field characteristics upon the economic viability of the CEPV concept. This chapter also considers two case studies: The Clair Field in the West of Shetland Islands and the Bonga Field offshore Nigeria. The results from the Economic Model are examined in detail to ascertain the economic viability and operational issues at each of these locations.

Chapter Eight reports the conclusions of the investigation and identifies the key areas where further investigations are needed before a CEPV could ever become a commercial proposition.

2 The CEPV Concept

2.1 Introduction

This chapter explains the concept of the CEPV for generating 'clean' electrical power offshore using natural gas and identifies the key enabling technologies.

The operating area for the CEPV involves selecting an appropriate site where stranded natural gas is available in sufficient quantities and where an opportunity exists to sequestrate CO_2, perhaps in nearby exhausted oil or gas fields or into the seafloor where the geological conditions are appropriate. In this Chapter such sites are identified to justify the further development and investigation of the CEPV concept.

Also in this Chapter, the CEPV is considered alongside other proposed systems to exploit stranded offshore natural gas and alongside offshore power generation in particular power generation on offshore oil and gas platforms and offshore wind energy. The purpose is to establish synergies in technology development and operational aspects that may then be exploited for the benefit of the CEPV's development.

Finally, this Chapter outlines the requirements of the CEPV design so as to allow a pathway for conceptualising its further development and analysing its feasibility in the remaining Chapters of this thesis.

2.2 The CEPV Concept

The CEPV is essentially an offshore power station that uses natural gas from offshore fields that have either no connecting pipeline to shore, known as 'stranded' natural gas, or are remote 'gas rich' oil fields i.e. offshore oil fields that are served by tankers to extract crude oil but where natural gas is re-injected because its transportation is too costly.

The CEPV receives natural gas onboard via a riser from a wellhead on the seabed; processes the natural gas onboard to extract valuable condensate and sweetens it so that it may be used safely by the prime-movers; extracts the energy contained in the natural gas using the prime-mover generator sets; extracts green-house gases from the exhaust and sequestrates them e.g. into a disused oil field, whilst exporting the electricity generated using a subsea cable to a shore connection, where it can be sold into the National Grid.

The CEPV compares to a shore-based natural gas power station in Table 3. The comparison is made by considering both building a new shore-based power station and a CEPV, and their individual operations so to allow a fair comparison.

Table 3 Top Level Comparison between CEPV and Shore-Based Power Station

Parameter	Shore-based Power Station	CEPV
Natural Gas	Received as 'clean natural gas' from the National Transmission System. Needs no further processing. Gas cost is dictated by market price.	Received onboard as 'dirty' natural gas from the wellhead via risers. Needs processing onboard the vessel. Gas is effectively 'free' as it lies abandoned and therefore has no market value.*
Power Plant	Conventional power plant.	'Marinised' conventional power plant required.
Emissions	Exhausted to atmosphere as the means to sequestrate CO_2 is not commonly available.	Greenhouse gases can be isolated and sequestrated into a disused field or into the seabed.
Electrical Connection	Connection to National Grid available via step-up transformers local to the power station.	Long distance subsea transmission cable needs to be connected to the National Grid. AC or DC transmission may be appropriate.
Environmental Friendliness	No – Contributes to global warming.	Yes – No contribution made to global warming.
Capital Cost	Land purchase Power station Connection to gas supply Connection to National Grid Service requirements	Licence to exploit natural gas Wellhead cost and riser Vessel Gas processing plant Power station CO_2 sequestration plant Subsea transmission cable Connection to National Grid
Running Cost	Gas consumption Cooling water charges CO_2 emissions tax National Grid connection cost Maintenance cost Manning cost Business rate taxes	National Grid cost Maintenance cost Manning cost Business rate taxes
Legislation	Requires planning permission to be built.	Government licence may be required to exploit natural gas in territorial waters.

*Discussions with Shell and BP.

Both power stations could potentially use the same type of power plant to generate electrical power albeit a marinised version would be required for the CEPV. The shore-based natural gas power station would receive 'clean' natural gas whilst the CEPV would receive 'raw' natural gas that would need processing to remove sand, water and valuable condensates before feeding into the gas turbines or other prime-movers at the required temperature and pressure. The exhaust gases of the shore-based power station would be exhausted into atmosphere whereas the exhaust gases of the CEPV would be processed and the harmful greenhouse gases sequestrated, possibly into an abandoned oil field. This operation would make the CEPV a conventional power station with zero greenhouse gas emissions (the only allowable emissions being oxygen, nitrogen and water vapour).

Another major operational difference is that the CEPV would need to adopt a different manning strategy perhaps one that is similar to offshore oil and gas rigs i.e. periods spent onboard the CEPV and periods on leave with each period being around two weeks.

2.3 CEPV Key Technologies

The key technologies required by the CEPV are:

- A natural gas riser system referred to as an up-pipe that allows the natural gas to be imported from the wellhead to the CEPV.
- A natural gas processing system to 'clean' the gas for combustion in the electricity generating plant.
- An electricity generating system that burns the natural gas and generates electricity e.g. diesel generators or gas turbine generators.
- Electrical power conditioning system onboard the CEPV that conditions electrical power ready for transmission.
- Subsea electrical transmission system that connects the CEPV to the shore and the National Grid.
- An exhaust treatment system that allows greenhouse gases to be extracted for sequestration.
- A sequestration system that allows greenhouse gases to be compressed and pumped to the sequestration wellhead on the seafloor via a down-pipe.
- A vessel to house the above equipment, the ship's own service needs e.g. propulsion, and to provide the crew with accommodation.

These technologies are now briefly considered below along with a view as to their development status and suitability for the CEPV.

2.3.1 Natural Gas Riser System

A natural gas riser system for the CEPV would consist of wells that have been drilled into the 'natural gas' field or 'oil and gas' field, by a specialist drilling rig. A cap on the seafloor would form the wellhead, and a riser system (which allows for the variations in water depth through tidal action and vessel drifting) would connect the well to the CEPV gas processing plant. The connection to the CEPV could potentially be a fixed system should the CEPV be a 'rig type' design or a swivel connection for a floating vessel to allow for vessel movement.
The number of wells and risers supplying the CEPV would depend upon the required gas flow for the electricity generating plant and the required level of redundancy in the gas supply system. The greater the number of wells and risers the greater the rate of gas flow but also the greater the initial cost.

2.3.2 Natural Gas Processing Plant

The Natural Gas Processing Plant will receive 'raw' natural gas from the riser system at an unknown pressure and temperature, so it must be processed to remove sand, water, condensates, and other unwanted impurities to 'sweeten' the natural gas prior to it being fed to the prime-movers at the required temperature and pressure. This involves various stages using such machines as compressors and centrifuges, and chemical compounds to induce chemical reactions such as to remove Sulphur.

Natural gas processing is a well understood science since processing plants of this nature have been used on offshore platforms and rigs at sea for a considerable period of time as well as larger units ashore[33]. The size of the plant needed for the CEPV could potentially be larger than those already at sea depending upon the required gas flow which in turn depends upon the power rating of the plant. Diesel engines and gas turbine generators are commonly used offshore to generate electrical power on offshore platforms and these prime-movers use processed natural gas from the wellhead for their fuel source[34].

2.3.3 Prime-Mover Generator System

The CEPV requires an electricity generating plant in the region of 250 – 500 MW with the lower value being considered a realistic 'Base Case' when considering CEPV cost and risk by using a design evaluation matrix, which will be discussed in Chapter Five. The prime-movers convert the calorific energy contained in natural gas into mechanical energy whilst the generators convert mechanical energy into electricity. Conventional prime-mover systems include diesel-engines burning natural gas (usually known as dual fuel engines) or gas turbines which are more commonly used; and steam plant where the natural gas is burnt in a boiler to produce steam that is subsequently used in a steam turbine e.g. LNG tankers. The generator could be a conventional synchronous generator or possibly an induction generator as used by offshore wind farms.

2.3.4 Exhaust Treatment with CO_2 Sequestration

The exhaust from the prime-movers will contain harmful greenhouse gas emissions which need to be sequestrated to ensure the electricity produced is 'clean'. The exhaust will also contain gases, such as Nitrogen, that are not normally harmful and these can be returned back to the atmosphere.

The prime-movers burn natural gas with air to produce mechanical energy and exhaust gases:

Natural Gas + Air = Energy + Exhaust Gases

where,
Exhaust Gases contains greenhouse gases and atmospheric gases.

The exhaust gas could therefore be processed to extract the greenhouse gases which must then be compressed and pumped into a storage space e.g. sequestrated into an exhausted oil field. The gases would therefore pass through the 'down-pipe' to the sea floor to a sequestration wellhead passing through non-return valves into the subterranean cavity.

CO_2 capture and storage systems are not commonly used by electrical power stations as they exhaust straight into the atmosphere. The CEPV cannot draw on technical experience in the power generation industry and must look to other industries such as the oil and gas companies where CO_2 is sequestrated to provide an oil lift, and also in remote oil fields where it is common practice to sequestrate the natural gas that is dissolved in recovered crude oil by pumping it back down the well into the field[35].

2.3.5 Electrical Power Conditioning and Subsea Power Transmission System

The generated electricity needs to be exported from the CEPV to market. This needs to be done using a subsea cable, which connects the CEPV to the National Grid. Transmission of electricity can either be by HVAC or HVDC. HVAC and HVDC subsea transmission systems are used worldwide to interconnect electrical distribution systems. An example of a subsea HVAC is 32.5 km 230 kV Cebu-Leyte link in the Philippines[51]; and an example of a subsea HVDC is the 73 km 270 kV England-France Interconnector[51]. Furthermore, subsea transmission is used by offshore wind farms these being over short distances e.g. Vindenby wind farm in Denmark[36]; and also subsea transmission systems that supplies electrical power from shore to offshore oil and gas platform e.g. Troll A platform in Norway[37]. Clearly there is significant experience in subsea electricity transmission systems upon which the CEPV can depend.

2.3.6 Vessel

A vessel is needed in which to house: The natural gas processing plant; the prime-mover generator system; the exhaust gas treatment plant and CO_2 sequestration system; and the electrical equipment and cable needed for subsea transmission of the electrical power.

The vessel will need to facilitate three connections; the two fluid connections being the imported natural gas and exported greenhouse gases for sequestration; and one electrical power connection being the cable for exporting the electrical power.

The vessel options are wide-ranging extending from fixed platforms to jack-up platforms to FPSOs to semi-submersibles. The type of vessel selected for the CEPV will depend upon many different and conflicting factors including required size, depth of water, and locations.

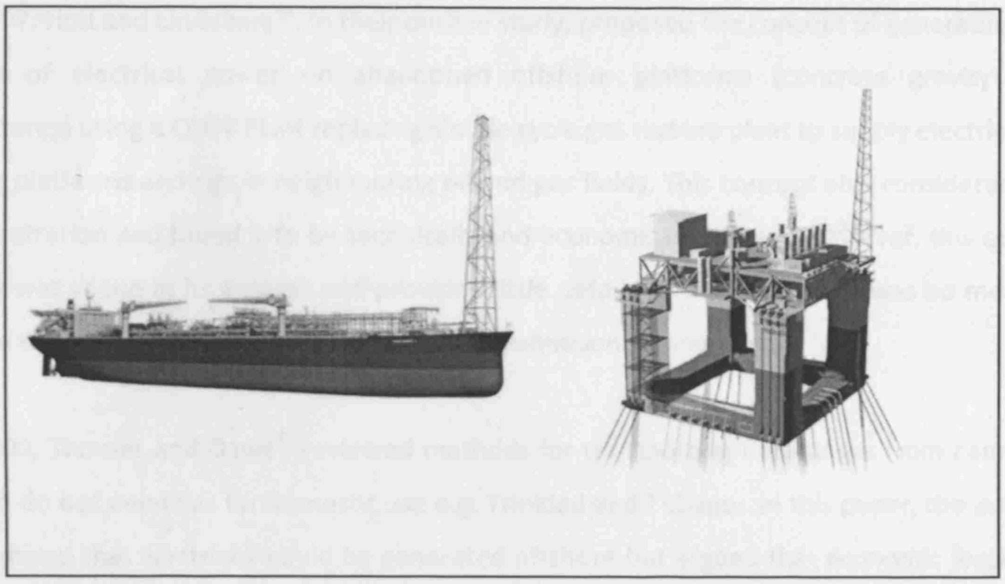


Figure 7 FPSO[38] (Left) and Semi-Submersible[39] (Right)

Fixed platforms are static as they rest on the seabed whilst jack-ups are floating vessels which can be maneuvered into position and then the legs lowered to allow the platform to be raised clear of the waterline since its legs will rest on the seabed. FPSOs are floating 'tankers' which have considerable volume and which are used for far offshore oil recovery. The semi-submersible is used in the offshore oil and gas industry often in a support role. The latter two vessel types often use dynamic positioning i.e. to remain precisely above a fixed point on the seabed regardless of the most severe weather and sea-state conditions. These vessels can be seen in Figure 7. Clearly vessel technologies exist upon which the CEPV can potentially rely.

2.4 Literature and Patent Review

There have been a few research projects looking at the generation of electricity offshore using natural gas either as platform-to-platform or platform-to-shore arrangement. These proposals are now briefly reviewed below.

In 1996, Stewart[40] studied the development of offshore platform electrical power system design in the UK's Continental Shelf. In this paper, it was suggested that further development of electrical power systems was unlikely because of future decline in production. The electrical power needs of production platforms would more often be met in the future by importing liquid fuels or by electrically connecting to neighbouring platforms.

In 1997, Holt and Lindeberg[41], in their outline study, proposed the concept of generating 300 MWe of electrical power on abandoned offshore platforms (concrete gravity base structures) using a CCGT Plant replacing simple cycle gas turbine plant to supply electricity to other platforms and rigs in neighbouring oil and gas fields. This concept also considered CO_2 sequestration and found it to be technically and economically viable. However, this outline study was vague in its analysis and provided little detail, for instance there was no mention of the source of the fuel and any electricity transmission arrangements.

In 2000, Thomas and Dawe[42] reviewed methods for transporting natural gas from countries which do not need gas for domestic use e.g. Trinidad and Tobago. In this paper, the authors recognised that electricity could be generated offshore but argued that economic feasibility is a concern simply because the costs of installing a subsea cable could be as expensive as a pipeline in shallow waters.

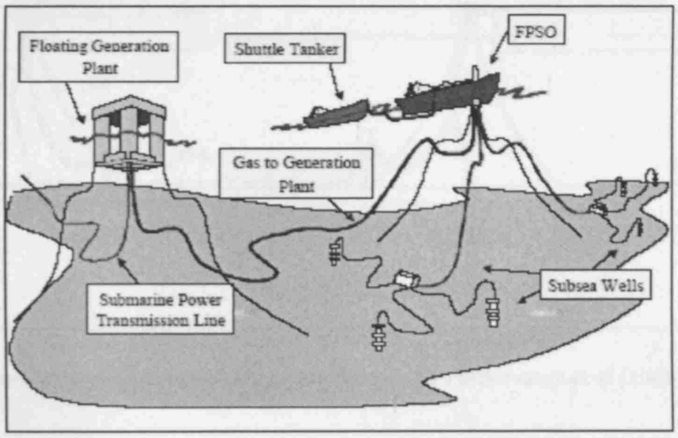


Figure 8 Conceptual Field Arrangement for Floating Generation Plants by Hill et al (2002)[43]

In 2002, Hill et al[43] proposed a novel concept of generating electricity offshore using natural gas from deepwater fields in the Gulf of Mexico to supply electrical power to other offshore platforms. The arrangement consists of multiple platform or vessel designs, as seen in Figure 8. The gas processing plant and the power generation plant are located on separate platforms or vessels. However, this arrangement made no provision for CO_2 sequestration and lacks considerable design detail.

A US Patent has been filed in 2005 by Poldervaart et al[44] of Single Buoy Moorings Inc. for a similar design to Hill et al. (above), as seen in Figure 9. The design consists of a generating vessel (110) which houses the turbine-generator sets (114, 116), a power line (138) connects the generating vessel to the process vessel (112) that processes the natural gas. The process vessel provides fuel to the generating vessel via a gas conduit (136). An additional feature of Poldervaart et al's design is the ability of the process vessel to process and offload liquefied natural gas to a shuttle tanker (106) for export to market.

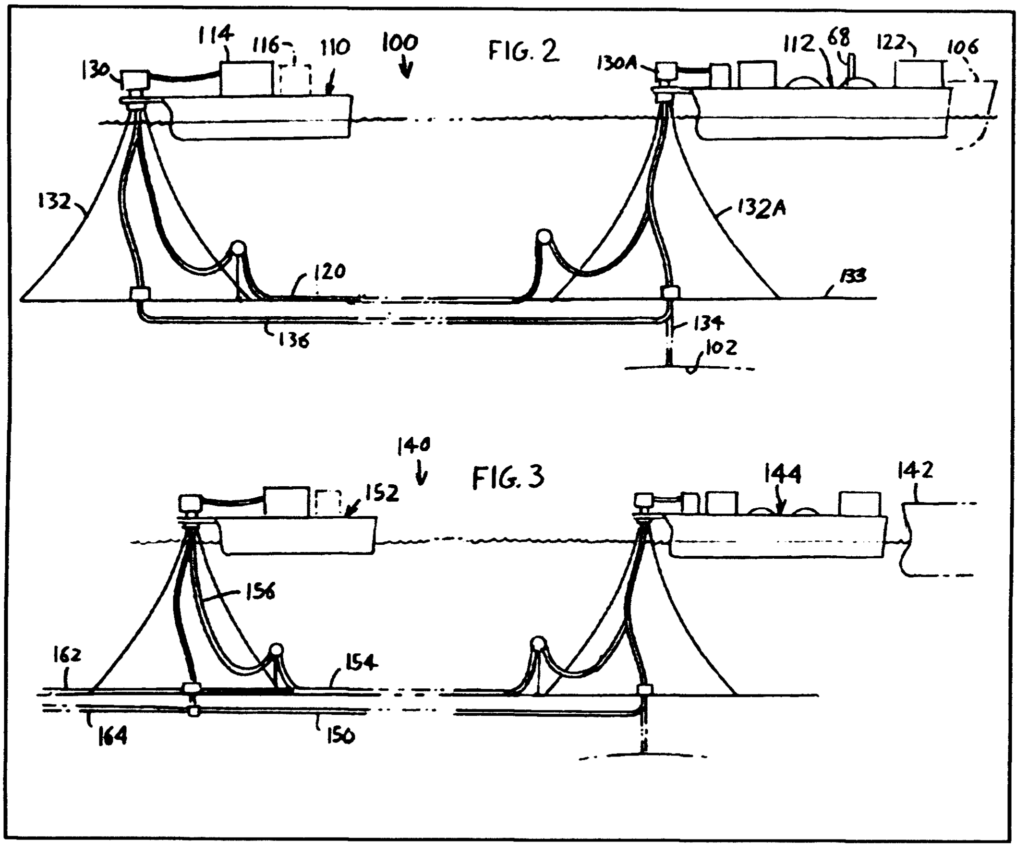


Figure 9 Floating Power Generation System by Poldervaart et al (2006)[44]

There are similarities between Poldervaart et al and Hill et al's designs which include both suggesting a multiple platform or vessel design with the gas processing facility and electricity generating plant separated at some distance apart; and neither author considered provision for CO_2 sequestration.

In summary, Stewart concluded that power generation using gas turbine driven generators has been in service in the offshore industry for many years and is a well understood technology. In his paper, Stewart predicted that the ratings of future generators will increase following developments in power electronics which impacts upon demand. Holt and Lindeberg's proposal for using an abandoned platform to house a generating facility to supply electricity to neighbouring platforms has suggested a way for larger generating capacity offshore. Hill et al and Poldervaart et al's proposals are similar in that both suggested the use of FPSO but separating the generating plant and gas processing plant onto different vessels.

Considering the state-of-the-art in offshore power generation there is an opportunity for the CEPV to build on past studies albeit these are very limited in number and in depth and quality of their analysis. The CEPV therefore remains a novel idea.

2.5 Initial Evaluation of Potential CEPV Sites

Figure 10 is an Oil and Gas map of the North Sea in which the major oil and gas fields can be seen. Offshore gas rich fields and gas rich oil fields in shallow and medium water depth fields, such as those in the southern and central North Sea, use fixed subsea pipelines to take the oil and gas ashore to terminals for processing and eventual consumption. An example is the Forties Field (shown by the arrow in the map) which is some 180 km offshore Aberdeen, where several offshore platforms feed into a subsea pipeline to transport the 'raw' hydrocarbons ashore for processing at the Grangemouth Refinery[45]. Such subsea transportation methods are now well established, the technology is mature and the solution economically attractive for large fields where water depth is not onerous i.e. they can justify the high cost of the installation of a subsea pipeline because significant quantities of hydrocarbons are being transported.

Some fields offshore are not served by pipeline because either they are too small to justify the cost or they lie too far offshore in deep water. Such exploited fields are usually oil fields where the oil is extracted and then stored in a large FPSO which is then lightered by shuttle tankers which will transport the oil to a refinery ashore[46]. In this arrangement any natural gas extracted with the oil is used to power gas turbine electrical generators to power the platform and/or re-injected into the oil well thereby being used to assist in lifting the oil. When the oil is exhausted the field is abandoned but it can often contain significant quantities of natural gas[46].

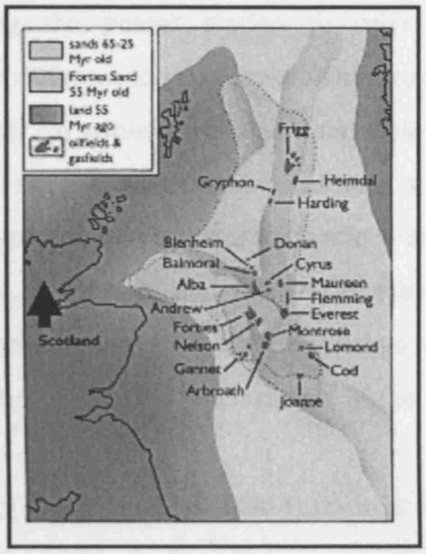


Figure 10 Oil and Gas Map of the North Sea[47]

There are also other predominantly natural gas fields some of which are considered 'marginal fields' since they are in water too deep or too far offshore to be served by a pipeline[48]. Field size can be too small meaning that the laying of pipelines to transport the natural gas ashore will not be cost effective.

As already mentioned, there are many small offshore gas fields that lie abandoned and that do not have sufficient gas to warrant and justify the high costs of installation of a pipeline. Additionally, the only option available for the offshore oil operator that exports oil via tankers rather than pipeline is to dispose off the natural gas by re-injecting it into the oil field since flaring it is prohibited. Reinjection incurs expense without revenue e.g. to support the running cost of the compressors.

2.6 CEPV and Similar Technologies

One of the areas of technology that the CEPV could lean on is the usage of land-based prime-mover technology e.g. diesel engines, gas turbines and steam turbines. These prime-movers are widely used on land and their technologies are mature. However, one of the technical challenges of using land-based prime movers at sea is that the design must address the migration of the land-based technology to the marine environment (marinisation). Diesel engines, aero-derivative gas turbines and steam turbines have been in used successfully in the marine environment however these have tended to be at relatively low powers when comparing to a large shore-based electricity generating station[49]. Marinisation therefore involves designing the power station to operate at sea where ambient environmental conditions are different to shore-based plant conditions. The air at sea tends to be more humid and will contain saltwater, the primary cooling medium at sea is seawater rather than air or fresh-water as used ashore. Bearing forces on rotating machinery must be capable of operating in a dynamic environment i.e. various sea-states with various vessel motions (surge, sway, heave, roll, pitch, and yaw). Generated voltage levels at sea are predominantly 440 V although in recent years higher voltages have been used e.g. 11 kV for some cruise liners[50] whilst ashore generated voltages are in the region of 25 kV.

The other area of technology that the CEPV could lean on is subsea transmission systems. This is also a mature area of technology where high power transmission systems and subsea power cables have been used extensively to transmit electricity from one country to another over long distances e.g. the 170 km 400 kV DC Denmark-Germany link[51]. This would present a technical challenge for the CEPV where there is a need to find an acceptable means of exporting the generated electricity from the vessel using a 'state of the art' subsea power transmission cable whilst at the same time the vessel is connected to two 'riser pipes' coming up from the seafloor, one being used for importing the natural gas (up-pipe) and one for exporting the captured CO_2 into a disused well (down-pipe) without limiting the passive weathervaning of the vessel too much or by exposing the risers or cable to excess stress and fatigue loading.

2.7 CEPV Outline Requirements

On board the CEPV there will be a power station. This consists of separate parts. The gas processing plant is responsible for cleaning and preparing the natural gas for use by the power station including storing valuable condensates. A module is also required for treating exhaust gas to extract the greenhouse gases for sequestration. The prime-mover module will burn the natural gas to produce mechanical power. The CO_2 sequestration plant will compress and pump greenhouse gases into a depleted gas field via a wellhead on the seafloor. The electrical generation module consists of generator sets and associated switchboards, auto-synchronising systems (for paralleling the generators), and electrical protection systems. The transmission module will consist of transformers and the transmission converter if HVDC is to be used, and the onboard termination point of the riser cable. The vessel will require a gas flare for use in emergencies.

The CEPV itself requires no propulsion as it is envisaged that it is towed to its operating site and then moored, although a thrusters system to assist with weather vaning may be desirable in some vessel types. The onboard hotel (accommodation) facilities would be those normally required of an oil and gas vessel with a high degree of safety considered in the design of the accommodation and evacuation routes built into the design at an early stage. The CEPV will require a helicopter deck and a refuge area. Mooring arrangements for small service vessels are also to be provided to allow stores to be unloaded.

It is envisaged that the CEPV is capable of operating throughout most of the year. Major maintenance periods at sea are considered for every two years with other maintenance periods arranged as dictated by the power plant requirements. A docking maintenance period would be expected every five years or as dictated by the classification society[52].

2.8 Summary

This chapter explained the concept of the CEPV for generating 'clean' electrical power offshore using natural gas and has identified the key technologies that are needed to enable its implementation.

The CEPV has been compared alongside a conventional shore-based power station. This analysis presented several areas of similarity and differences between the CEPV and a conventional shore-based power station. Key Technologies for the CEPV have also been identified. The overview undertaken in this chapter has identified key areas that need investigating in subsequent chapters: Prime-movers, natural gas preparation and CO_2 sequestration; transmission systems and subsea transmission cable; and vessel design.

The literature and patent review carried out has concluded that previous proposals in offshore power generation have not considered the CEPV design and operation as a whole and therefore it remains a novel electricity generating solution. Potential operating areas for the CEPV have been identified. Stranded natural gas is available in sufficient quantities and opportunities exist to sequestrate CO_2 into depleted oil and gas fields.

3 Electricity Generation, Natural Gas Processing and CO_2 Sequestration Technologies for the CEPV

3.1 Introduction

This chapter is concerned with the design of the electricity generating plant, the natural gas processing plant, the exhaust gas processing plant and the means to enable sequestration of greenhouse gases, for the CEPV concept.

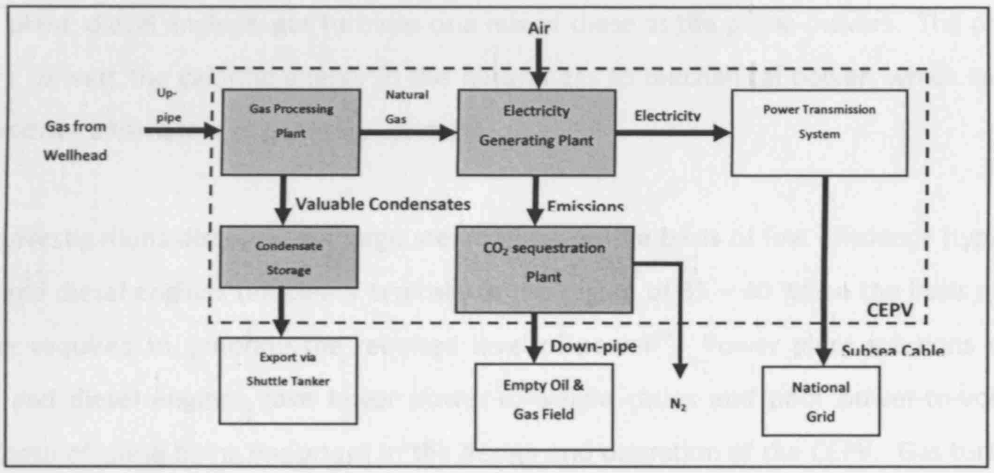


Figure 11 Gas Processing, Electric Generating and CO2 Sequestration Plants Arrangement for the CEPV

Figure 11 shows a block diagram of the main CEPV processes from the point natural gas is obtained from the wellhead to the export of electricity, valuable condensates and the sequestration of greenhouse gases.

A natural gas processing plant is required to condition the raw natural gas from the wellhead so as to extract valuable condensates and prepare the natural gas to meet the specific fuel requirements of the prime-movers. The exhaust emissions from the electricity generating plant need to be processed to allow greenhouse gases to separated and then sequestrated whilst *N* and water vapour are returned to the atmosphere.

Current electricity generating technologies are reviewed in this chapter including their combustion processes. A number of prime-mover generating scenarios are selected based upon the CEPV requirements that were initially established in Chapter Two. For each prime-mover generating set the natural gas flow rate and exhaust gas emissions are established in order that the gas processing plant and CO_2 sequestration plant can be appropriately sized.

3.2 Prime-mover Generator Plant

3.2.1 Overview

In Chapter Two it was established that the CEPV requires an electricity generating plant in the region of 250 – 500 MW with the lower value being considered a realistic 'Base Case' when considering CEPV cost and risk. The options for generating electricity are to use a steam plant, diesel engines, gas turbines or a mix of these as the prime-movers. The prime-movers convert the calorific energy in the natural gas to mechanical power, which can be used to drive alternators to generate electricity.

Initial investigations discounted a large steam plant on the basis of low efficiency (typically 25 %) and diesel engines (efficiency typically in the region of 35 – 40 %) on the basis of the number required to generate the required level of power[53]. Power plant solutions using steam and diesel engines gave lower power-to-weight ratios and poor power-to-volume ratios both of these being important in the design and operation of the CEPV. Gas turbines demonstrated good efficiency (typically in the region of 50 %) when used with a waste heat recovery unit (WHRU)[54].

3.2.2 Gas Turbine Cycles

The main gas turbine cycles are listed against their current availability in Table 1 below. This table is followed by a short description of each gas turbine cycle so as to explain and identify the most appropriate power plant for the CEPV but further details on each cycle are provided in Appendix 1.

Table 4 Gas Turbine Power Cycles

Cycle	Availability
Simple	Yes
Cheng (STIG)	Yes
Intercooled-Regenerative	Yes
Regenerative	Yes
HAT	Emerging
CCGT	Yes

Simple Cycle Gas Turbine

The simple cycle (Brayton Cycle) is the ideal gas turbine cycle and its simplest form is shown in Table 4. Ambient air is compressed in a compressor and fed to the combustion chamber where fuel is added. This isentropic compression does not require heat input. The resulting combustion produces a constant gas stream that expands in the turbine to drive the generator.

In simple cycle gas turbine, specific work is a function of compressor pressure ratio, r_c and specific power reaches maximum when r_c is approximately 10 and thermal efficiency is approximately 0.3655. Maximum thermal efficiency for the simple cycle is approximately 0.4 when r_c is approximately 23. The simple cycle has superior specific power but inferior thermal efficiency compared to regenerative and intercooled-regenerative cycle.

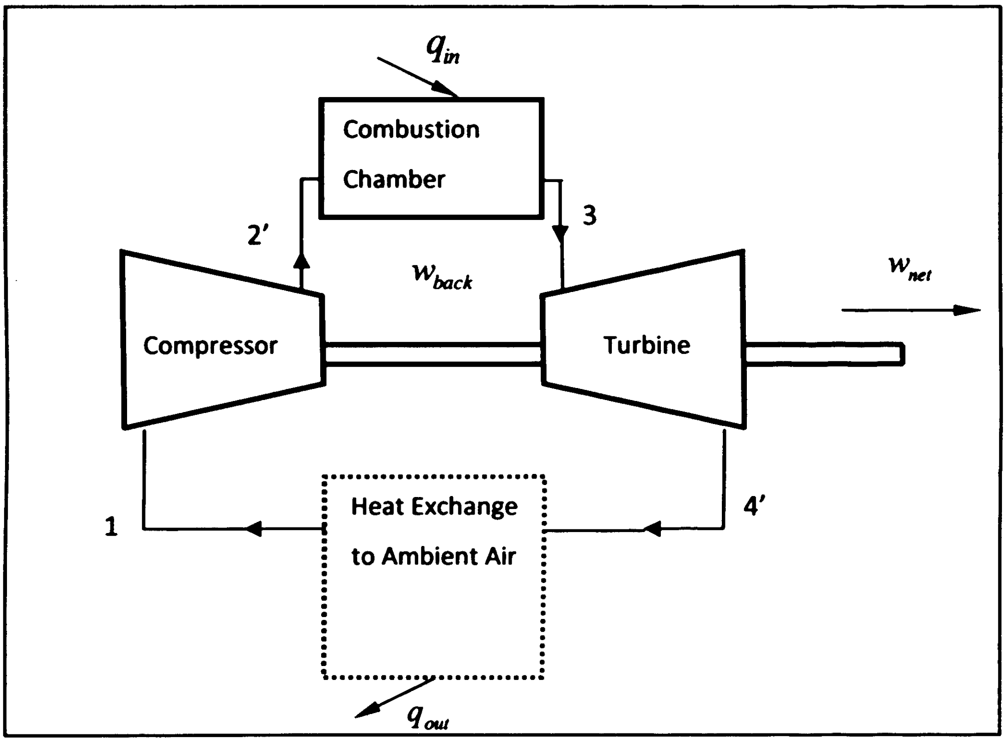


Figure 12 Simple Cycle Gas Turbine

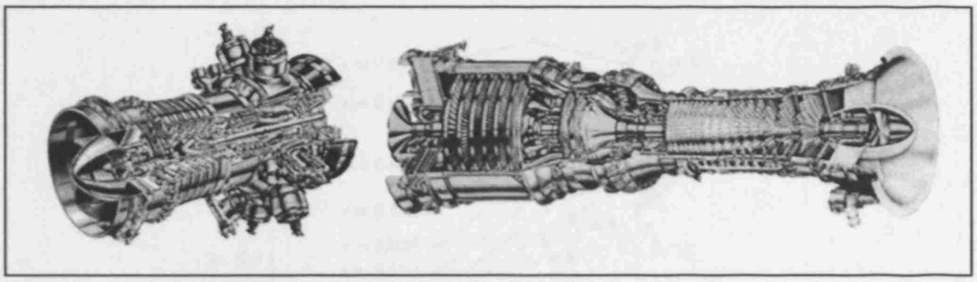


Figure 13 Rolls Royce RB-21156 (left) and General Electric LM-2500+57 (right)

Commercially available simple cycle gas turbines suited for the CEPV include the Rolls Royce RB-211 and the General Electric LM-2500+ as seen in Figure 11 Gas Processing, Electric Generating and CO2 Sequestration Plants Arrangement for the CEPV. Both of these are multi stage gas turbines meaning that they have a two stage compressor and a twin turbine arrangement. The high pressure (HP) compressor is driven by the high pressure (HP) turbine and the low pressure (LP) compressor is driven by the low pressure (LP) turbine. Multi stage gas turbines have a higher efficiency and superior power to weight ratio and are already extensively used in the marine environment especially for offshore rigs and naval warships.

Regenerative Gas Turbine

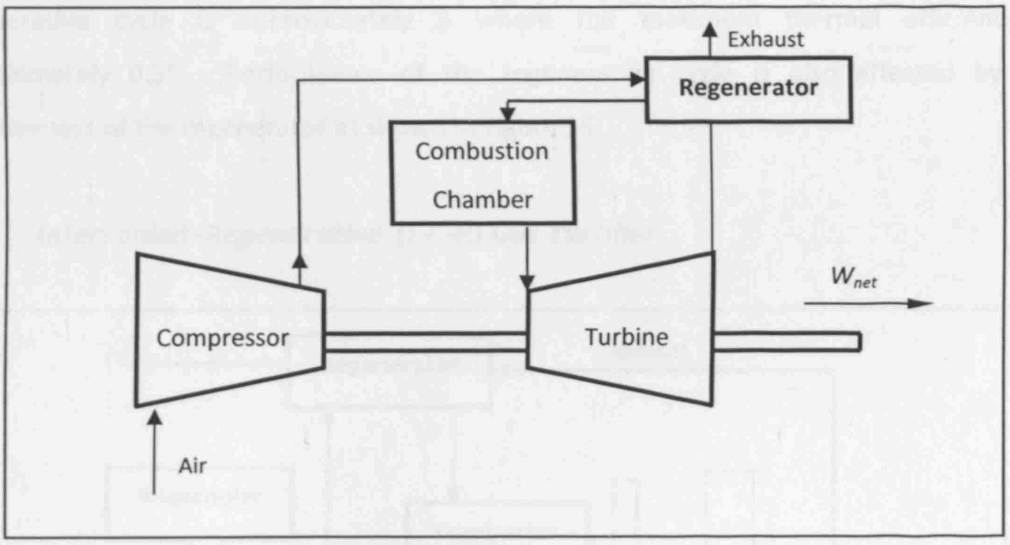


Figure 14 Regenerative Cycle

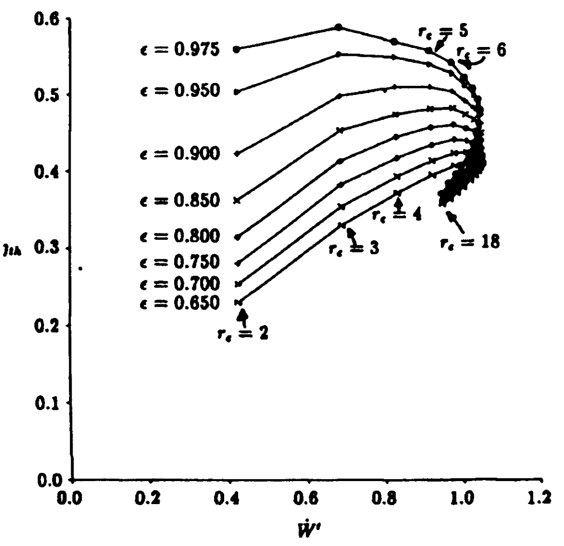


Figure 15 Effect of Regenerator Efficiency on Regenerative Cycle Performance[58]

In this cycle, as shown in Figure 14, the compressed air passes through a regenerator located in the exhaust path to increase its temperature prior to entering the combustor. In regenerative cycle, the specific work is a function of the compressor pressure ratio, r_c, which is also equal to the simple cycle55. The regenerator reduces energy input such that typical thermal efficiency for this cycle is 0.48. The optimum pressure ratio for the regenerative cycle is approximately 3 where the maximum thermal efficiency is approximately 0.55. Performance of the regenerative cycle is also affected by the effectiveness of the regenerator as shown in Figure 15.

Intercooled-Regenerative (I-C-R) Gas Turbine

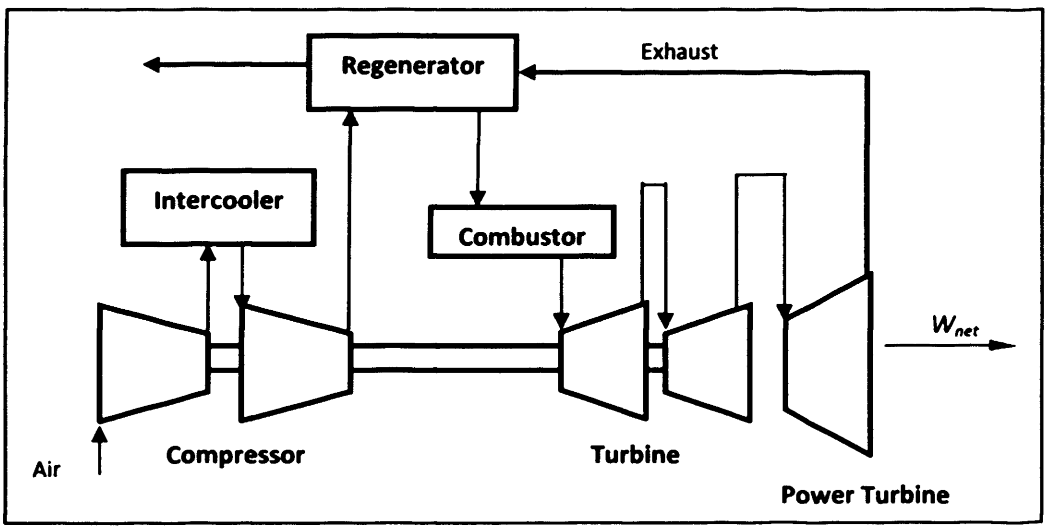


Figure 16 Intercooled-Regenerative (I-C-R) Gas Turbine

The intercooled-regenerative gas turbine is a Simple Cycle gas turbine with the addition of a regenerator in the exhaust path and an intercooler in between the compression stages as shown in Figure 16. The intercooler uses a different working fluid e.g. water to cool the compressed air upon leaving the first compressor and prior to entering the second compressor meaning that less work is required in the compression stage since air becomes more dense at lower temperatures. The regenerator transfers some of the heat from the exhaust gases leaving the turbine to the compressed air leaving the compressor.

This cycle improves fuel consumption over the Simple Cycle gas turbine by raising the air temperature prior to the combustion process. The intercooled-regenerative cycle has higher thermal efficiency but lower specific power over simple cycle55. This cycle has superior thermal efficiency and higher specific power over the regenerative cycle.

A common characteristic amongst the simple cycle, regenerative cycle, intercooled-regenerative cycle gas turbine is that as compressor pressure ratio increases thermal efficiency reaches a maximum then it declines as shown in Figure 17.

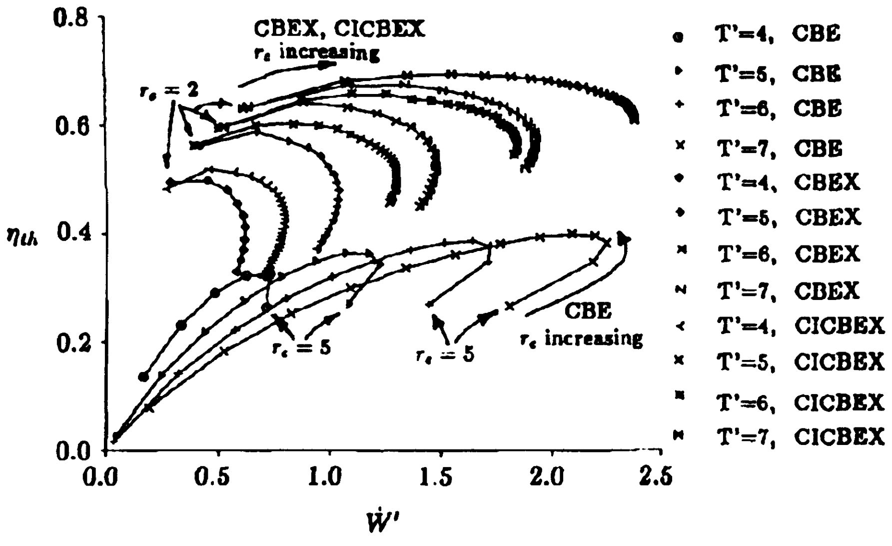


Figure 17 Thermal Efficiency Versus Specific Power for Simple Cycle (CBE), Regenerative (CBEX), and Intercooled-Regenerative Cycle (CICBEX) Gas Turbines[55]

Cheng Gas Turbine

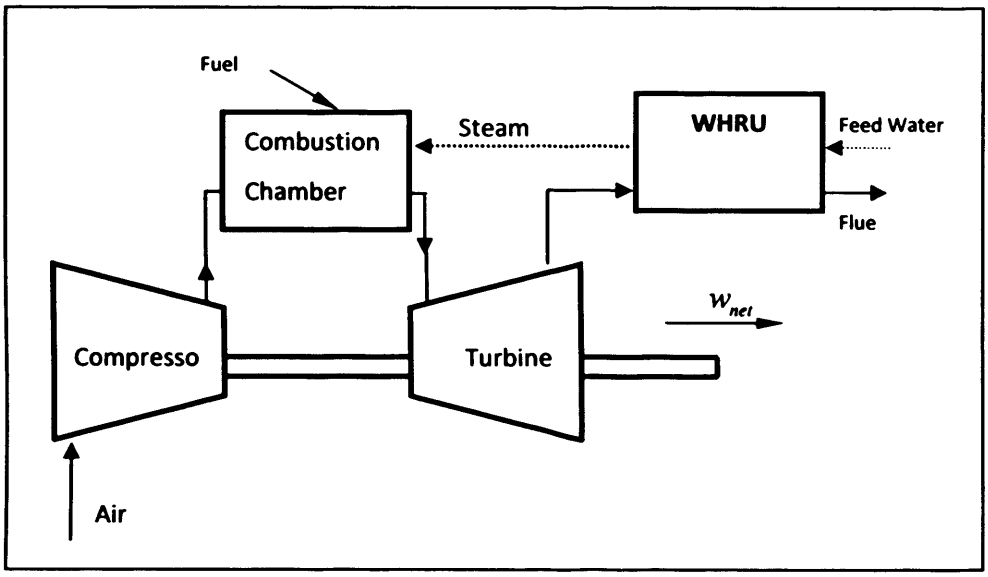


Figure 18 Cheng Cycle

In a Cheng gas turbine cycle, steam is injected into the combustion chamber along with the combustion gases as shown in Figure 18. The steam is generated from the exhaust gas using a waste heat recovery unit. This has a commercial name of STIG – STeam Injected Gas turbine[59]. Such turbines are commercially available in the 17 – 51 MWe range of output, representing power augmentation over the Simple Cycle gas turbines of about 10 % due to increased gas mass flow rate and higher specific heat[59]. Whilst requiring a lower initial capital expenditure than other gas turbine types e.g. CCGT, a supply of purified water is constantly needed as the injected steam is not recoverable.

Hat (Humid Air Turbine)

Humid air turbines use water injected into the compressor to achieve continuous intercooling during the compression stages thus reducing the compression work required. Such cooling allows more heat recuperation from the exhaust gases, including recovery of the injected water via condensation.

Further development of HAT has been carried out using swirl spray nozzles to improve water droplet formation in the compressor. Efficiency is claimed to be in the region of 55%, representing a significant improvement over Simple Cycle operation[60].

Combined Cycle Gas Turbine (CCGT)

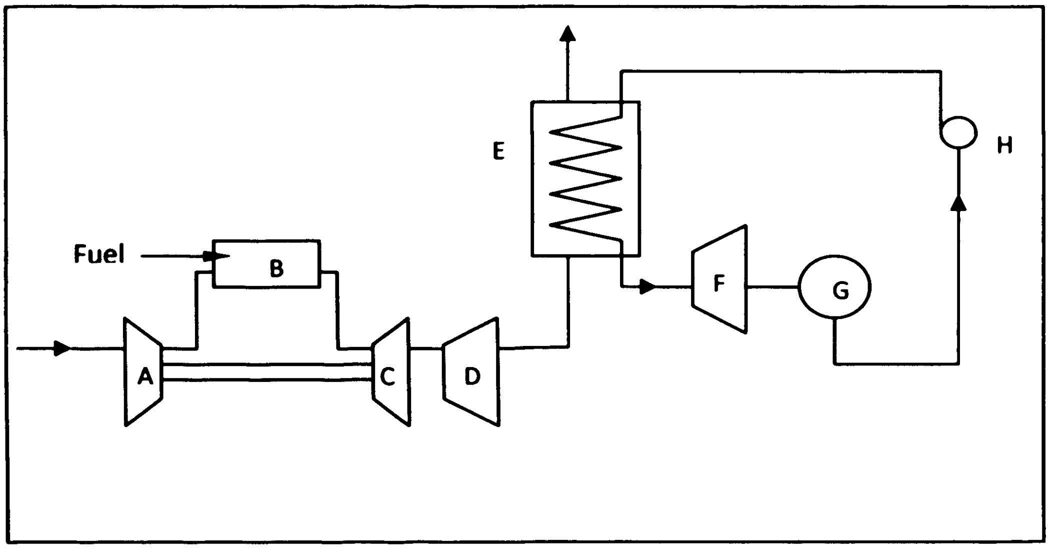


Figure 19 Combined Cycle[61]

A. Compressor, B. Combustion chamber, C. Compressor drive turbine, D. Power turbine, E. Heat recovery unit, F. Steam turbine, G. Condenser, H. Boiler Feed Pump

Efficiency of a gas turbine is dictated by the simple fact that exhaust gas leaves at a much higher temperature than the air entering the gas turbine. One way to improve gas turbine power plant efficiency is to combine the gas power cycle with a vapour (steam) power cycle. The gas power cycle exhaust temperatures are closely matched with the heat input temperatures needed by a steam power cycle. The transfer of this heat may be achieved using a simple heat exchanger located in the gas turbine uptake. The CCGT cycle is shown in Figure 19. Efficiencies can exceed 55%62. In addition, steam can be bled from the steam system for gas turbine injection or used for blade cooling.

Summary of Gas Turbine Types

- Simple cycle gas turbines are currently available and would meet the power range applicable to the CEPV. Many simple cycle gas turbines have already been marinised and have extensive service history in the offshore oil and gas industry and also in shipping especially warships. Their relatively low efficiency is not attractive for the CEPV.

- Regenerative gas turbines are suited to low power applications and are therefore not suited for the CEPV.

- Intercooled-regenerative gas turbine technology has been applied at relatively modest powers. Part load efficiency of these gas turbines is superior to simple cycle although full load efficiency is only marginally improved. Continued development of I-C-R technology is expected to migrate into larger gas turbines which suggest this gas turbine may be an option for the future. It is not really suitable for CEPV at the present time.

- Cheng (STIG) gives some improvement to simple cycle operation but involves a separate steam system. If a steam system is to be installed then the CCGT, with improved efficiency and steam/water recycling, would be a much better option for the CEPV.

- Combined cycle is currently available and extensively used in shore-based electrical power generating stations. This technology achieves the power ranges applicable to CEPV with superior efficiency over all the previously described cycles. The only difficulty is the marinisation of a large CCGT plant however the gas turbine used in CCGT have often been used as simple cycle engines in the marine environment.

Gas Turbine Generators Selection

Table 3.2 shows the range of selected gas turbines for the CEPV. The compendium consists of 14 different solutions using models selected from a wide range of manufacturers and was compiled after considering: Power/weight ratio, efficiency, redundancy, emissions, cost/kW, flexibility, downtime, plant weight and dimension.

Using the scores of the design evaluation matrix in Table 5 and also considering the requirement in Chapter Two for a 'Base Case' power plant in the region of 250 MW, then a 264 MW Rolls Royce Trent CCGT Plant consisting of four gas turbines and two steam turbines each rated at 51.9 MW and 28.2 MW respectively, has been selected as the 'Base Case'. The Rolls Royce Trent CCGT Plant uses the heat recovered from the gas turbines' exhaust to generate steam to drive smaller steam turbines. The configuration of four gas turbines and two steam turbines has the potential to allow the generating profile of the CCGT Plant to be optimised based upon the production profile of the gas field.

Table 5 Electricity Generating Plants[63]

No	Make and Model	Total Capacity, MW	Heat Rate, kJ/kWh	Efficiency, %	GT Design Power, MW (No)	ST Design Power, MW (No)	Design Evaluation Matrix Score
1	ABB-Alstom GTX-100	258	9720	37	43 (6)	-	324
2	ABB-Alstom KAX100-1	250.8	7040	51	42 (4)	20.7 (4)	337
3	ABB-Alstom KAX100-1	502	6950	52	42 (8)	20.75 (8)	259
4	MAN Borsig 8 FT8	279	6920	52	25.69 (8)	18.36 (4)	340
5	Rolls Royce Trent	264	6630	54	51.9 (4)	28.2 (2)	479
6	GE S207EA	267	7070	51	83.5 (2)	100 (1)	267
7	GE S109EC	263.2	6660	54	166.6 (1)	96.6 (1)	338
8	Rolls Royce RB-211	157	6620	54	31.75 (4)	12.45 (4)	240
9	Rolls Royce Trent	264	6630	54	51.9 (4)	28.2 (2)	467
10	ABB-Alstom KA8C2-1	328	7347	49	57.5 (4)	26 (4)	250
11	Ansaldo En. Cobra 164.3	400	6667	54	66.5 (4)	37.5 (4)	320
12	ABB-Alstom	502	6950	52	42 (8)	41.5 (4)	245
13	GE LM6000PC	259.5	8617	42	43.25 (4)	-	230
14	Guess*	258 MW	6545	55	43 (6)	-	215

* Make and model does not exist. Guess based upon a prototype.

3.3 Gas Flow

3.3.1 Overview

The type and size of the electricity generating plant dictates the natural gas flow requirement from the wellhead and also the required flow rate for sequestrating the greenhouse gases. Additionally the quality of the natural gas dictates the rate at which valuable condensates will be produced. The gas flows establish the size of the natural gas processing plant and the greenhouse gas sequestration plant and the tankage needed on the CEPV to store the valuable condensates.

3.3.2 Gas Flow Analysis

The composition of raw gas from a typical North Sea production platform is shown in Table 6. It consists of 97 % hydrocarbons (HC) of which the principal component is natural gas. Natural gas typically consists of Methane (CH_4, 93 % by volume), Ethane (C_2H_6, 3 % by volume), Propane (C_3H_8, 0.67 % by volume) and some other alkanes in minor quantities. All these hydrocarbon gases can be combusted in gas turbines. The remaining 3 % is made up of Nitrogen (N_2, 2.12 % by volume), Hydrogen Sulphide (H_2S, 0.43 % by volume), Carbon

Dioxide (CO_2, 0.34 % by volume), valuable condensates (0.05 % by volume) and other minor gases. Raw gas can arrive at the surface mixed with sand and water. Combustion of natural gas in the presence of oxygen (O_2) produces CO_2, water and heat. This reaction is shown in Equation 3.1, which represents the generic chemical reaction when an alkane is combusted in oxygen.

Table 6 Typical North Sea Natural Gas Composition[63]

Constituent	% Volume	Constituent	% Volume
Methane	93.00	Hexane	0.05
Ethane	3.00	Heptane	0.03
Propane	0.67	Octane	0.01
Isobutane	0.27	Nitrogen	2.12
Isopentane	0.08	CO_2	0.34
H_2S	0.43	Condensate	0.05

The amount of fuel i.e. natural gas required by the electricity generating plant onboard the CEPV can be determined from the plant's power rating and efficiency. Additionally, the quantity of oxygen and hence the air required for combustion can also be determined having a knowledge of the ambient air temperature and pressure.

$$C_nH_{2n+2} + O_2 \rightarrow CO_2 + H_2O + Heat \tag{3.1}$$

Nitrogen is present in the natural gas and in the air. Nitrogen can react with O2 at high combustion temperatures to produce NO_x gases including nitrogen oxide and nitrogen dioxide as shown by the chemical Equations 3.2 and 3.3. NO_x gases are harmful to the environment because they are both greenhouse gases and destroyers of the ozone layer[64].

Nitrogen Rejection Units can be used to remove low levels of nitrogen from the natural gas before it is combusted. Low NO_x combustors are often used with gas turbines to control combustion temperature and hence the production of NO_x. Such combustors would naturally be used onboard the CEPV to reduce to a minimum the production of NO_x. For example, Rolls Royce Trent series (generating plants 5 and 9) and RB-211 series (generating plant 8) would use Dry Low Emissions (DLE) technology where an eight canular staged combustion system is used to keep the NO_x emissions lower than 25 vppm[65,66].

$$N_2 + O_2 \rightarrow 2NO \tag{3.2}$$

$$N_2 + 2O_2 \rightarrow 2NO_2 \tag{3.3}$$

Figure 20 shows the proposed CEPV gas flow path for the Base Case power plant, a 264 MWe Rolls Royce Trent CCGT Plant which has an efficiency of 54 % at standard ambient air temperature and pressure (STP). The required natural gas flow rate is calculated to be 1.24 million m^3 per day based upon an average calorific value of 48.77 MJ/kg and the air intake requirement is 12.32 million m^3 per day based upon 20.9 % of oxygen in air. The electricity produced would be 264 MWe with approximately 250 MWe being exported to the National Grid since the CEPV itself could expect to consume in the region of 14 MW.

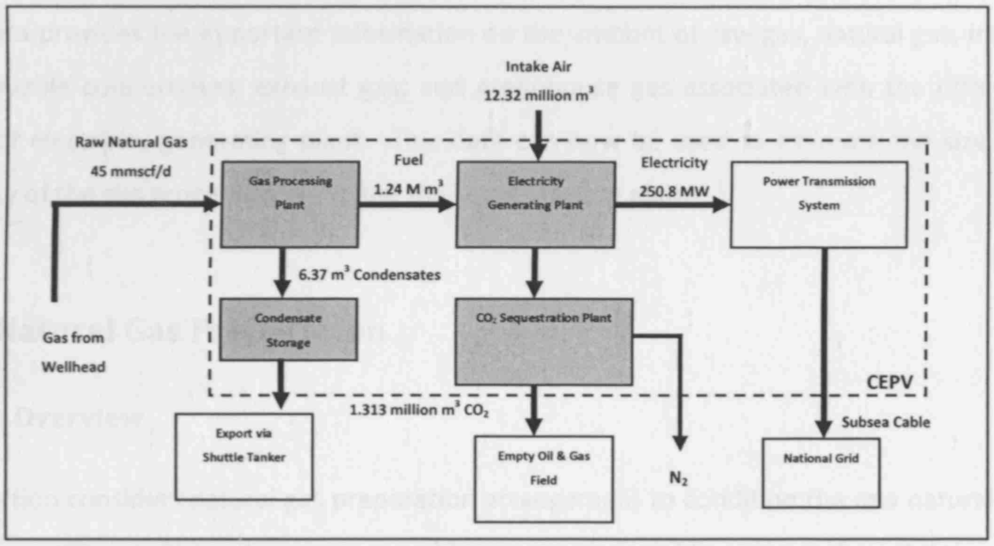


Figure 20 Flow of Energy for Base Case CEPV (Per Day)

From knowing the composition of raw gas as shown in Table 6 and the chemical equations 3.1 and 3.2, it is possible to analyse the gas flow processes and determine quantities and hence show that 45 mmscf of raw gas is required per day from the wellhead for the Base Case CCGT plant. Furthermore, 6.37 m^3 per day of valuable condensates can be extracted from the raw gas and stored onboard for collection by a shuttle tanker when a sufficient quantity has been collected. The quantity of exhaust gas produced is 33.7 million m^3 per day. Assuming predominantly CO_2, water vapour and nitrogen in the exhaust then 1.313 million m^3 per day of CO_2 is produced all of which needs to be sequestrated. Similar results for the other electricity generating plants as given in Table 5 have been generated and are shown in Table 7.

Table 7 Combustion Profile of 14 CEPV Scenarios

Gen Set	Output (MWe)	η (%)	Total NG req. per day (tonne)	Minimum gas flow to achieve maximum production	Total NG prod. per day (tonne)	Volume of NG prod. per day (million	O_2 req. per day (tonne)	Volume of intake air req. per day	CO_2 prod. per day (tonne)	Volume of CO_2 prod. per day (million

				(mmscf/d)		m^3)		(million m^3)		m^3)
1	258	37	1244	64	1256	1.76	4990	17.52	3481	1.87
2	250.8	51	877	45	883	1.24	3508	12.32	2447	1.31
3	502	52	1722	88	1726	2.42	6861	24.09	4786	2.57
4	279	52	957	49	961	1.35	3820	13.42	2665	1.43
5	264	54	872	45	883	1.24	3508	12.32	2447	1.313
6	267	51	934	48	942	1.32	3742	13.14	2611	1.4
7	263.2	54	869	45	883	1.24	3508	12.32	2447	1.313
8	157	54	519	27	530	0.74	2105	7.39	1468	0.79
9	264	54	872	45	883	1.24	3508	12.32	2447	1.313
10	328	49	1194	61	1197	1.68	4756	16.7	3318	1.779
11	400	54	1321	68	1334	1.87	5302	18.62	3698	1.98
12	502	52	1722	88	1726	2.42	6861	24.09	4786	2.57
13	259.5	42	1102	57	1118	1.57	4444	15.61	3100	1.66
14	258	55	837	43	844	1.18	3352	11.77	2339	1.25

This data provides the important information on the amount of raw gas, natural gas, intake air, valuable condensates, exhaust gas, and greenhouse gas associated with the different types of electricity generating plant. This data can now be used to estimate the size and capacity of the gas processing plant and the sequestration plant.

3.4 Natural Gas Preparation

3.4.1 Overview

This section considers natural gas preparation arrangement to condition the raw natural gas from the wellhead. This is to extract valuable condensates and to prepare the natural gas to meet the fuel requirements of the prime-movers. Typically, raw natural gas is a complex mixture of hydrocarbons and water, in both liquid and gaseous states. Solid and other contaminants can also be present in raw natural gas. The raw natural gas may also be unstable with its components undergoing rapid phase transitions as the stream is produced from several hundred meters deep in the gas field, at high temperature and pressure, to surface ambient conditions. It is important to remove solids and contaminants and to separate the raw natural gas into natural gas, valuable condensates, water and oily sludge.

On the CEPV the role of the gas processing plant is to provide a fuel gas that can be fed into the electricity generating plant and at the same time to extract valuable condensates for storage and later export. The gas processing plant has the following functions: Separates natural gas, condensates, oil and water imported from the gas producing well and conditions them.

3.4.2 Natural Gas Processing Scheme

The gas processing plant is shown in schematic form in Figure 21. Raw natural gas from the gas field is imported onto the CEPV via the gas wellhead and gas up-pipe to the swivel turret where it enters into the gas processing plant. The gas processing plant consists of a number of key stages in which solids and liquids are extracted and the remaining natural gas processed and prepared for combustion. These processes are explained in the following sections.

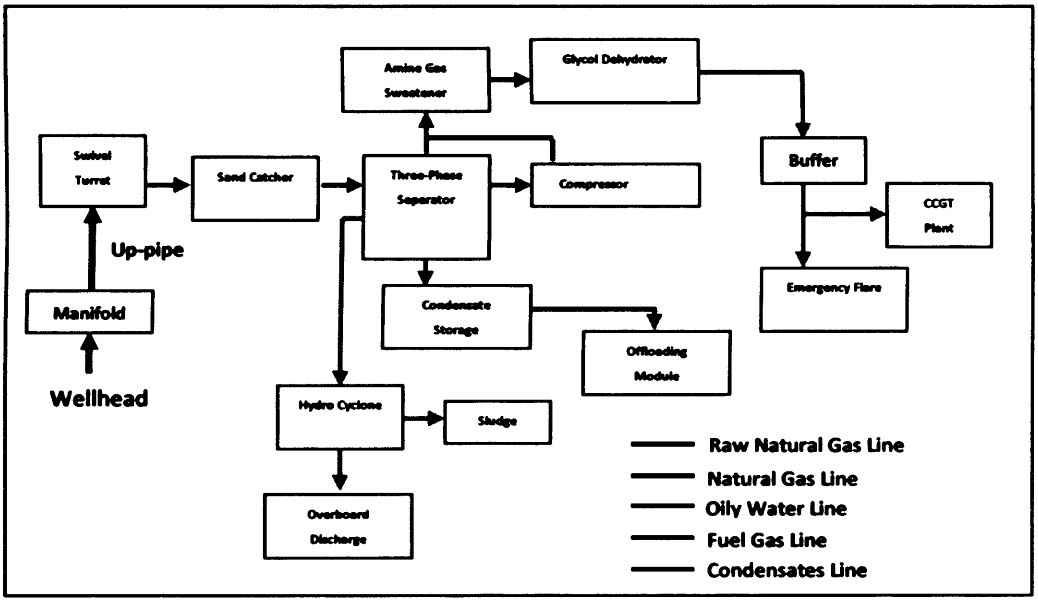


Figure 21 Schematic of the Gas Processing Plant

Manifold and Swivel Turret

The manifold receives the gas from the gas up-pipe or pipes where it is mixed to form a single stream that feeds the gas processing plant. The Swivel Turret is provided so that weather vaning of the CEPV is possible thereby allowing the up-pipes to maintain their independence to avoid undue flexing and twisting. Figure 22 shows a gas manifold and a swivel turret.

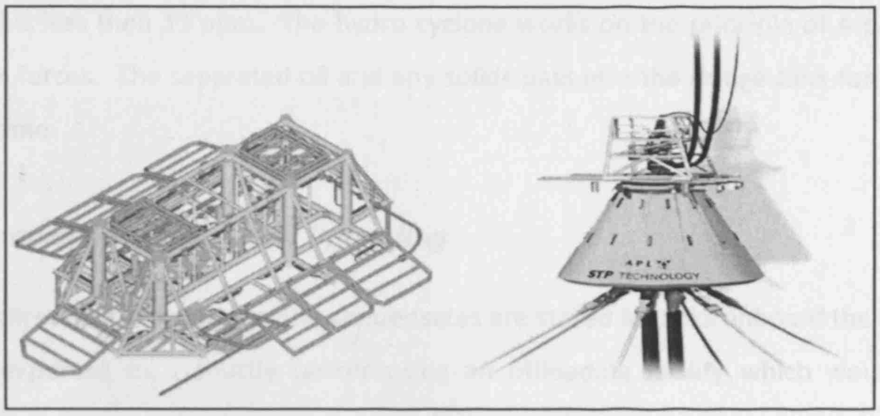


Figure 22 Left, Gas Manifold[67]; and Right, Swivel Turret (STP)[68]

Sand Catcher

The sand catcher is a filtering vessel that filters the natural gas to remove large particles such as sand and other entrained solids prior to the gas entering the three-phase separator.

Three-Phase Separator

The raw natural gas stream typically arrives at the CEPV at a pressure of 6,895 kPa and a temperature of 60 °C[69]. The three-phase separator separates the raw natural gas into pure natural gas for further processing and combustion, valuable condensates for storage and export, and water which is subsequently processed to remove sludge before being discharged overboard.

A three-phase separator, commonly called a "free-water knockout separator", is a vessel that may be designed horizontal, vertical or spherical. The three-phase separator operates on the principle of pressure reduction to separate natural gas from entrained liquids in the raw natural gas stream. Furthermore, the three-phase separator allows the liquids to stand for periods up to seven minutes permitting dissolved gas to escape through the formation of small gas bubbles that rise to the surface. The liquids are separated by gravity and leave the vessel at its bottom through different valves whilst the natural gas leaves the vessel at the top passing through a mist extractor to remove any remaining liquid droplets.

Hydro Cyclone

The water from the three-phase separator passes to the hydro cyclone unit where entrained oil is separated from the water to ensure that oil content in the water that is disposed overboard is less then 15 ppm. The hydro cyclone works on the principle of separation by centrifugal forces. The separated oil and any solids pass into the sludge tank for offloading at a later time.

Condensate Storage and Offloading

From the three-phase separator, the condensates are stored in tanks onboard the CEPV until they are exported to a shuttle tanker using an offloading facility which would include condensate pumps, manifold and connecting hoses.

Amine Gas Sweetener

Raw natural gas can contain Hydrogen Sulphide (H_2S) and this is removed using an amine gas sweetener. Raw natural gas containing H_2S is commonly called 'sour gas' because of its rotten egg smell and it is considered 'sour' when H_2S is present in amounts greater than 5.7 mg/m^3. 'Sour gas' is undesirable because the H_2S can be extremely harmful to health and corrosive to machinery and it may also form sulphuric acid in exhaust gases[70].

The primary process for sweetening 'sour gas' is achieved using an amine solution that removes H_2S. The 'sour gas' passes through a tower called an absorber, which contains the amine solution. This solution absorbs H_2S by chemical reaction. This process can operate over temperature ranges of 30 – 50 °C and pressure of around 20 MPa[71]. There are two principle amine solutions used, monoethanolamine (MEA) and diethanolamine (DEA)[72]. Both these compounds are in liquid form and absorb the H_2S contained in the natural gas so that the exiting natural gas is virtually free of H_2S. The amine solution used can be regenerated to remove the absorbed H_2S allowing it to be recycled. The extracted H_2S will be stored onboard the CEPV until it is offloaded.

Glycol Dehydrator

The 'sweetened' natural gas stream is called 'wet' natural gas and it next enters the Glycol Dehydrator[73]. The glycol dehydration unit is also called a TEG Plant and consists of an absorber and a reboiler. The absorber is a vertical unit which allows for glycol solution flow with maximum gas and liquid contact. The absorber operates at the pressure of the incoming natural gas stream which enters the bottom of the absorber. The gas comes into contact with the lean glycol which enters at the top and any remaining water content is removed from the gas by the glycol forming 'dry' natural gas at the exit of the absorber.

When the glycol solution becomes saturated with water, it is pumped through a reboiler which boils the glycol mixture and separates the glycol from the water. Water has a boiling point of 100 °C and glycol has a boiling point of 204 °C. This boiling point enables water to be removed from the glycol solution, allowing it to be reused in the dehydration process.

Buffer

A buffer is provided to store natural gas to ensure the CCGT Plant is fed natural gas at a constant pressure. The buffer would essentially consist of a large pressure vessel fitted with a relief valve that would allow excess pressure to be relieved to the emergency flare.

Emergency Flare

An emergency flare is provided to ensure that a natural gas flow path exists to avoid unnecessary build-up of pressure in the natural gas flow path should the CCGT plant suddenly shut down.

3.4.3 Gas Processing Plant for the CEPV

The gas processing plant consists of a number of key stages whereby solids and liquids are extracted and the remaining natural gas processed and prepared for combustion. A number of key technologies have been identified as suitable for the CEPV and these have been explained briefly. For the electricity generating plants identified in the previous section it is calculated that the gas processing plant should be capable of handling raw natural gas flows of 27 – 88 mmscf per day. The composition of the gas delivered by the processing plant for combustion is shown in Table 8.

Table 8 Processed Gas Composition

H2S	Negligible
CO_2	Approx. 0.05%
Gas pressure	5 MPa
Temperature	100 °C
Specific Gravity	Ave. 0.62-0.72 (rel.air)
Water Content	Negligible

3.5 CO_2 Capture and Sequestration

3.5.1 Overview

For the electricity generating plants identified earlier in this chapter it is calculated that the exhaust gas flows will be in the range of 33.7 – 65.8 million m^3 per day. The exhaust gas will mainly contain CO_2, N_2 and water vapour but is only the CO_2 that will need to be sequestrated since N_2 and water vapour are naturally occurring in the atmosphere and are harmless. The corresponding range of CO_2 in the exhaust gas from the electricity generating plants will be in the range of 1.313 – 2.567 million m^3 (54,700 – 107,000 m^3 per hour) this representing approximately 4 % of the exhaust gas by volume.

3.5.2 CO_2 Capture

There are three basic methods for capturing CO_2 which are Pre Combustion Capture, Post Combustion Capture and Oxy-Fuel Combustion Capture. These are briefly discussed below.

Pre Combustion Capture

This method involves reacting natural gas with oxygen to obtain a 'synthetic gas' which consists of carbon monoxide and hydrogen. The carbon monoxide is then reacted with steam in a catalytic reactor to generate CO_2 and hydrogen[74]. Using a physical or chemical absorption process the CO_2 can be separated, resulting in hydrogen fuel which could be fed to the gas turbines. This technology is commonly used in chemical industries which produce hydrogen and CO_2 for chemical manufacturing e.g. fertilisers and food products e.g. soft drinks.

Oxy-Fuel Combustion Capture

In this method, pure oxygen is used for combustion instead of air, resulting in a flue gas that is almost a pure CO_2 stream that can be transported to the sequestration site to be stored. Oxygen is usually separated from the air cryogenically which requires a lot of energy i.e. 15 % for a 500 MW power plant[75]. The technology is promising but the initial separation of oxygen from the air requires a lot of energy.

Post Combustion Capture

This method involves capturing diluted CO_2 from the flue gases produced in the combustion process. Whilst there are several methods for achieving this e.g. calcium cycle capture and cryogenic capture, the most commonly used method is amine scrubbing. The exhaust gas is passed through a carbon separator which uses amine solvent to extract the CO_2 from the exhaust gases before it is discharged into the atmosphere. The CO_2 is captured by the amine solvent in an exothermic process[76] that involves reducing the exhaust temperature to 40 °C. Such cooling would be achieved using seawater fed heat exchangers. The CO_2 is then removed from the amine by passing it through steam in a stripper allowing the amine solvent to be reused. The regeneration of the amine solvent requires heat at temperatures of 100 – 150 °C. CO_2 leaves the stripper at about 80 °C saturated with water. Current technology (ABB-Lummus System) is available for commercial application and is capable of capturing up to 16,290 m^3 of CO_2 per hour[77]. The arrangement for post-combustion CO_2 capture is shown in Figure 23.

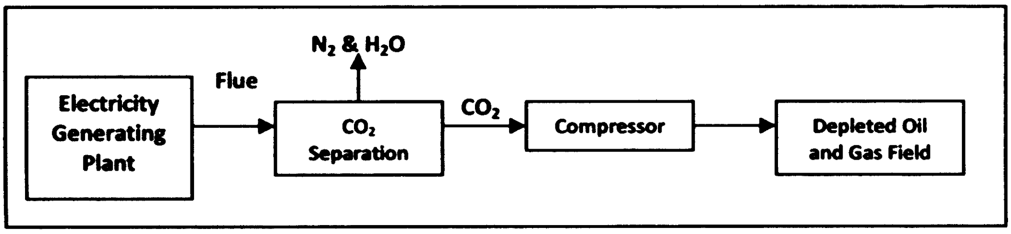


Figure 23 Post Combustion Capture Scheme

3.5.3 CO_2 Capture Method for the CEPV

The method chosen for the CEPV is Post Combustion Capture using amine solvent simply because it is a technology that is well understood with over 60 years experience and it is currently used in other industrial applications e.g. a few land based power plants[78]. Post combustion CO_2 Capture units can be pre-fitted into prime movers at their manufacturing stage without any significant modifications[79].

3.5.4 CO_2 Sequestration

Geological sequestration, making use of geological structures of known fluid retention capacity, is an alternative to accelerating the natural ocean sequestration cycle[80]. The assumption behind all geological sequestration techniques is that CO_2 will be injected at depths greater than 800 m below sea level. Free CO_2 is in the supercritical phase at such depths (where the hydrostatic pressure exceeds the critical pressure), which have typical conditions of 25-30°C and 10 MPa[80]. This means that gas density is greater, thus increasing capacity for storage without the need for special pressure conditions and pumping requirements hence lowering the costs of sequestration[81].

Consider Figure 24 which shows different methods of storing CO_2 by geological means. CO_2 storage in deep saline aquifers is not considered for CEPV application because the technology is not yet well understood and more research is needed. An example of saline aquifer storage is Sleipner field in the North Sea. CO_2 storage in deep unminable coal seams is also not considered as an option for the CEPV as there are no suitable coal seams in the North Sea[82]. CO_2 storage in depleted oil and gas fields is considered as the main option for the CEPV because it is a well understood technology and there are significant experiences of its usage at large scale[83] and is therefore investigated further in this section.

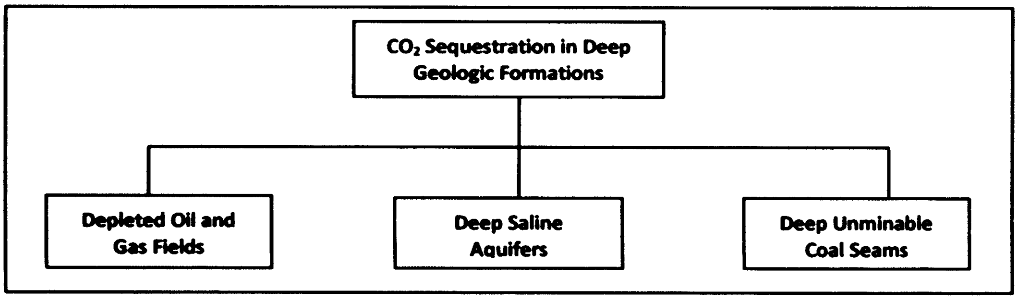


Figure 24 CO_2 Sequestration in Deep Geologic Formations

Captured CO_2 would need to be compressed and exported through the down-pipe to the sequestration wellhead, where a non-returning valve can be provided to prevent back flow of CO_2 into the system. Present technology in CO_2 compressors that can be used would include MAN Turbo's 8 stage or 10 stage CO_2 compressors originally designed for coal-fired power plants and capable of compressing 138,000 to 161,000 m^3 of CO_2 per hour[84]. For the Base Case CEPV only one compressor is needed.

CO_2 Sequestration in Depleted Oil and Gas Fields

Extensive exploitation of hydrocarbon reserves has left many conventional oil and gas fields depleted and disused[85]. The advantages of CO_2 disposal are that such formations are completely documented and that every reservoir is a proven trap of a known volume. In addition there exists reusable production equipment such as wellheads and a seabed pipeline already on site.

Typically about 30 % (by volume) of the oil and up to 90 % (by volume) of the gas initially in place is recovered from a field in primary production[86]. It is therefore unlikely that any oilfield owner would allow CO_2 disposal without exploitation of the remaining reserves, or appropriate financial compensation. As most gas reserves are up to 90 % (by volume) exploited at the primary phase, it is anticipated that injection of CO_2 into depleted gas reservoirs without further recovery is acceptable. In gas cases, serious consideration must be given to the inevitable pressure build-up concerned with injecting CO_2 into an otherwise sealed hydrocarbon trap[87].

Exploration costs are considered to be minimal due to previous field developments and equipment is already in place, as previously mentioned. As a result the volume of any one known field can be reasonably accurately estimated. The storage capacity of all depleted hydrocarbon reserves depends on numerous factors, including volume, porosity, permeability, and reservoir temperature and pressure[88].

Hydrocarbon reservoirs are proven traps, known to have held hydrocarbons for millions of years. Thus retention times for CO_2 are estimated to be over 100 years[89]. Inherently in Enhanced Oil Recovery, CO_2 is always co-produced with the oil causing 'fizzy' oil, which requires additional treatment once extracted[90].
As mentioned earlier in Chapter Two, in a paper by Holt and Lindberg[91], the concept of providing centrally generated power for Norwegian offshore platforms is studied as it offers CO_2 sequestration opportunities in abandoned wells and nearby aquifers while also allowing CO_2 emission reduction through a greater generation efficiency. The power plant is based on a 90 m x 70 m platform with 50,000 tonnes carrying capacity, and has a power production capacity of 375 MWe. It is estimated to need only 2,520 m^2 area but to weigh 13,200 tonnes.

As the recovery efficiency of the amine scrubbers is only 85 % when the CO_2 concentration is 3 % and improves to 90 % or more for 8 % concentration, 40 % of the exhaust gas is re-circulated to improve CO_2 concentration[92]. The separation plant is estimated to weigh

12,500 tonnes and to be accommodated on the CEPV. Similar plant already existing covers an area 111 m x 55 m and is 45 m high, but this could be compacted considerably.

3.6 Summary

This chapter has concentrated on gas processing plant, prime movers and CO_2 capture and sequestration technology for the CEPV.

Gas turbines are considered as first choice for the CEPV. Gas turbines demonstrate acceptable efficiency when used with a waste heat recovery unit (WHRU). The main gas turbine cycles have been considered against their current availability so as to identify the most appropriate power plant for the CEPV and a Base Case electricity generating plant has been identified.

Table 9 Specification of the Base Case CEPV Key System

Equipment	Specifications/Requirements	Comments
CCGT electricity generating plant	CCGT Plant for Base CEPV: A 264 MWe Rolls Royce Trent plant which consists of 4 x 51.9 MWe gas turbine generator and 2 x 28.2 MWe steam turbine generator. Volume: 11,713 m^3	Intake air: 12.32 million m^3 per day. Fuel consumption: 1.24 million m3 per day. Exhaust Generated: 33.7 million m^3 per day.
Gas Processing Plant	Gas processing plant to consist of a three phase separator, condensate offloading facility, amine sweetener, glycol dehydration plant, natural gas buffer and emergency flare. Volume: 13,500 m^3	Minimum gas flow for Base Case CEPV: 41 mmscfd. Natural gas required: 1.24 million m^3 per day. Condensate production: 6.37 m^3 per day. 1x MAN Turbo Compressor
CO_2 Capture and Sequestration Plant	Post-combustion capture with geological sequestration into depleted oil and gas field. Volume: 274,725 m^3	Minimum Capacity for Base Case CEPV: 33.7 million m^3 exhaust gas per day. 1.313 million m^3 CO_2 per day.
Turret	Turret to accommodate: natural gas up-pipe, CO_2 down-pipe and cable riser Volume: 3534 m^3	Natural gas: 41 mmscfd CO_2 1.313 million m^3 per day 250 MWe generated electricity

The role of the gas processing plant is to provide a fuel gas that can be fed into the electricity generating plant and at the same time extract valuable condensates for storage and export. Whilst gas processing technologies are well understood and have been widely used, the challenge lies in reducing its size and housing it onboard the CEPV.

Several methods for CO_2 capture are available. Post combustion capture is the most well understood and technologically mature and has been selected for the CEPV. However, the power required to extract the CO_2 from the exhaust gas and to pump it down to a depleted oil and gas field is high and will inevitably adversely affect the economics of the CEPV. There are several methods for the sequestration of CO_2 offshore with the most attractive option being re-injection into depleted oil and gas fields using known and proven technology.

The gas processing and power generation technologies needed for the CEPV are therefore available. The specification of the Base Case CEPV mechanical system, as shown in Table 9, is carried forward to Chapter Five which considers the design and layout of the CEPV itself and into Chapter Six in which the Economic Model is developed.

4 The CEPV Electrical Generation and Transmission System

4.1 Introduction

Electrical power generated onboard the CEPV by the 'Base Case' CCGT Plant, or by any of the other electricity generating plants discussed in Chapter Three, would be exported via a subsea cable to the National Grid. In this Chapter, the requirements for the CEPV's electrical generation and transmission system are established and research undertaken to establish a viable solution for the electrical generators, transmission, cables and power conversion systems.

Electricity is usually generated using synchronous machines although induction generators are commonly used in wind energy turbine generators. The generated voltage in conventional shore based power stations is usually in the region of 25 kV[106], this being considerably higher than the voltage levels usually found in marine vessels. The method of electrical generation for the CEPV and the appropriate voltage are investigated.

Transmission of the electrical power from the CEPV to the National Grid would be via a cable laid on the seafloor. Traditional methods of subsea transmission are HVAC and HVDC and both of these have been investigated for their potential use with the CEPV. There are many different types of cable for each voltage type and these are reviewed and appropriate solutions proposed. For DC transmission a power converter onboard the CEPV is needed to convert the generated electrical power from AC to DC and a power inverter ashore is needed to convert the DC transmission power back to AC to connect to the National Grid. Transformers will also be needed at each end to match generated, transmission and National Grid voltages. The impact of having converters and transformers onboard the CEPV is investigated.

The riser section of the transmission cable, the part of the cable that rises from the seafloor to the vessel, is a novel aspect of the overall generation and transmission system design and it is therefore investigated in some detail to establish key design drivers and performance parameters.

4.2 Electrical Generators

4.2.1 Selection of Electrical Generator Type

Gas turbines and steam turbines tend to operate at high rotational speeds typically in excess of 3,000 rpm[93,94,95] hence there is a need for step-down gearboxes to match the speed of the turbine to the speed of the generators in order to generate electricity at an appropriate frequency (typically 50 or 60 Hz).

There are many methods to generate electricity but the two types of generators most commonly used are the synchronous machine and the induction machine. The induction machine is commonly used in wind generators[96] where it is directly connected to an AC electrical supply from which it is able to draw reactive power needed to enable it to generate real power. The rotational speed of the induction generator varies with power output since the induction generator operates super-synchronously and at a negative slip[96]. The limited control over output voltage, frequency and power and in particular its unsuitability for use with DC transmission systems means that induction generators are not the preferred option for the CEPV[97].

The synchronous machine is more commonly used for electricity generation and can be designed as having either a round rotor or a salient pole rotor[98,99]. The round rotor synchronous generator is used at high rotational speeds since the air gap in the machine is constant around its periphery and therefore incurs low windage loss[100]. The salient pole synchronous generator has a non-uniform air gap and is more commonly used at lower speeds, below 1,000 rpm, and hence it is more suited for use with diesel engines[101].

The most suitable generator sets for the CEPV would be two-pole or four-pole round rotor synchronous generators generating electrical power at 50 Hz so that synchronisation to the National Grid would be possible[98]. A brushless design with a main exciter and a pilot exciter and using a Closed-Air-Cooling-Water (CACW) system to remove heat arising from internal losses[102] appears to be the most appropriate solution. The internal arrangement of a typical brushless synchronous generator is shown in Figure 25. These types of generator are widely used in the marine environment[103]. The generated voltage would be controlled by the field current using an Automatic Voltage Regulator and the output frequency would be controlled using the prime-mover (gas turbine or stream turbine) governor[104].

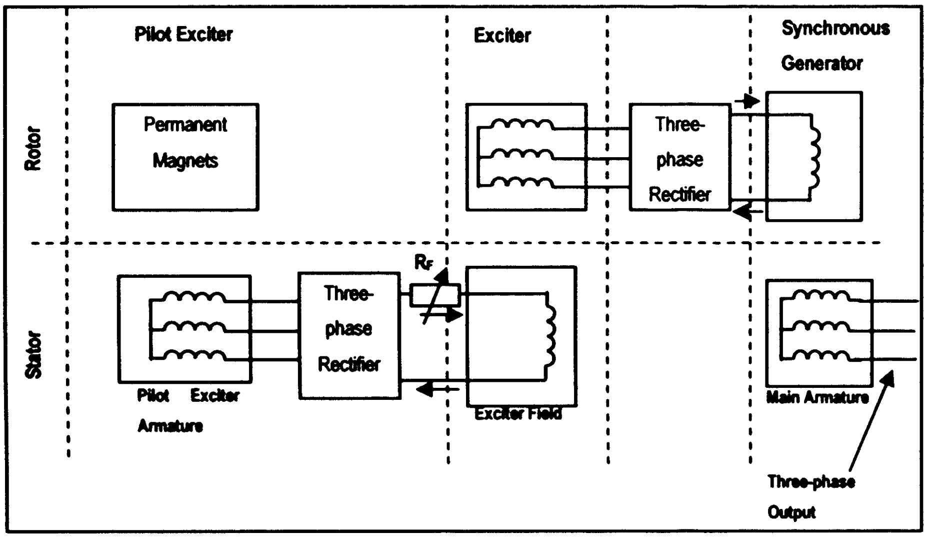


Figure 25 Internal Arrangement of Synchronous Brushless Generator[105]

4.2.2 Generated Voltage Levels

Generators at shore based power stations typically generate voltages in the range of between 20 - 30 kV[106]. A lower voltage is generated as compared to the transmission voltage simply to avoid excessive insulation levels in the generator. Step-up transformers are used to match the generated voltage with the transmission voltage typically 275 kV or 400 kV.

In a marine electrical system electricity tends to be generated at the highest voltage and distributed around the vessel at the same or at a lower voltage[107]. For example, electrical propulsion systems in ships generate electrical power at voltages up to 11 kV and distribute to the propulsion motors at that voltage and to the ship's services at a lower voltage typically 440 V using a step-down transformer[108]. On large oil and gas platforms, generated voltages are higher, up to 25 kV, however the distribution method adopted is similar[109]. In recent years there has been a tendency in the offshore industry to link a number of platforms together using a subsea transmission cable to reduce their cost of operation[43]. In such arrangements the generated voltage is stepped-up using transformers before being transmitted using subsea cables as three-phase HVAC. Voltage levels in the marine environment tend to be dominated by cable size primarily because of the maximum bending radius for large diameter cables i.e. high current-carrying cables and fault levels and fault currents which need to be within the capability of the switchgear[108].

The CEPV will generate electricity at the high voltage of 25 kV and step-up the voltage using transformers for transmission either by HVAC or HVDC. The switchgear will be a mix of vacuum to protect each generator and SF6[110] to enable large fault current protection for the feeders linking the transmission system.

Consider the Base Case CEPV electricity generating system where the power levels of the gas turbine generators are 51.9 MWe and 61.1 MVA and the steam turbine generators are 28.2 MWe and 33.2 MVA. Marine generator transient reactance is typically 0.22 per unit.

For the gas turbine generators by defining base power as 61.1 MVA and base voltage 14.4 kV (phase voltage) then the base current is calculated at 1,414 A and base impedance is 3.36 Ω. By calculating marine generator reactance to be 0.74 Ω then the fault current is 6,435 A.

For the steam turbine generators by defining the base power as 33.2 MVA and base voltage 14.4 kV (phase voltage) then the base current is 769 A and base impedance is 6.26 Ω. By calculating marine generator reactance to be 1.38 Ω then the fault current is 3,500 A.

Clearly for this electricity generating plant the continuous current and fault currents for all generators fall within the capability of vacuum breakers which currently have maximum ratings of 5,000 A continuous and 50,000 A symmetrical fault current level[110].

When generators are operating in parallel the effect is to reduce the source impedance and hence increase the fault level and the fault current. The main circuit breakers linking the generators to the transmission system onboard the CEPV are therefore those breakers that feed the transformers. Here the fault current rises significantly and beyond the capability of vacuum circuit breakers hence SF6 circuit breakers would need to be used here. In addition to fault level the inrush transformer current could also be potentially high and beyond the safe working limit of vacuum breakers.

4.2.3 Electricity Transmission Technology

Appendix 2 presents all the different types of transmission systems that were considered for the CEPV. There are two established methods for transmitting generated electricity subsea that could be exploited for the CEPV to the National Grid link, these being HVAC and HVDC. The generated frequency would be 50 Hz (to match the National Grid frequency) and the voltages of the generators would be 25 kV. For three-phase HVAC subsea transmission system the generated voltage, transmission voltage and the National Grid voltage would be matched using transformers. For HVDC transmission, the generated AC would be stepped-up using a transformer and converted to HVDC using a converter. Onshore an inverter would allow the transmitted DC to be inverted to AC and then matched to the National Grid using a transformer. There would be no DC circuit breakers as isolation would only be provided to and from the transformers. These two systems are seen in Figure 26 and Figure 27.

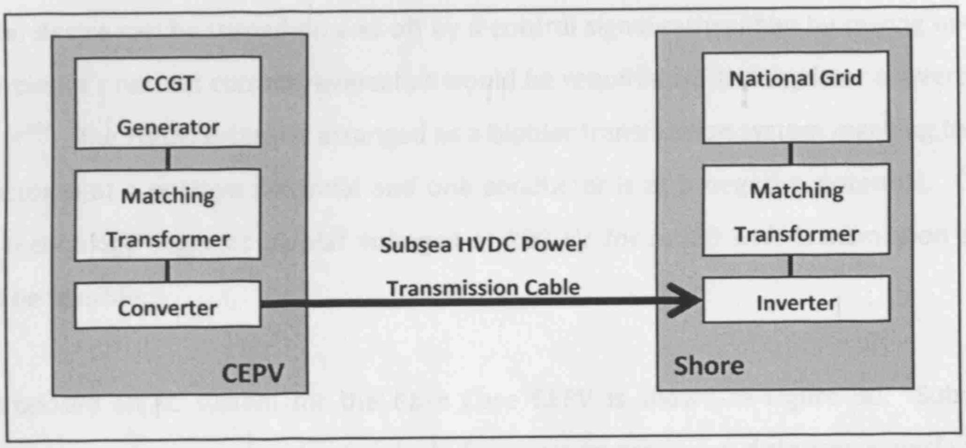


Figure 26 HVDC Transmission System

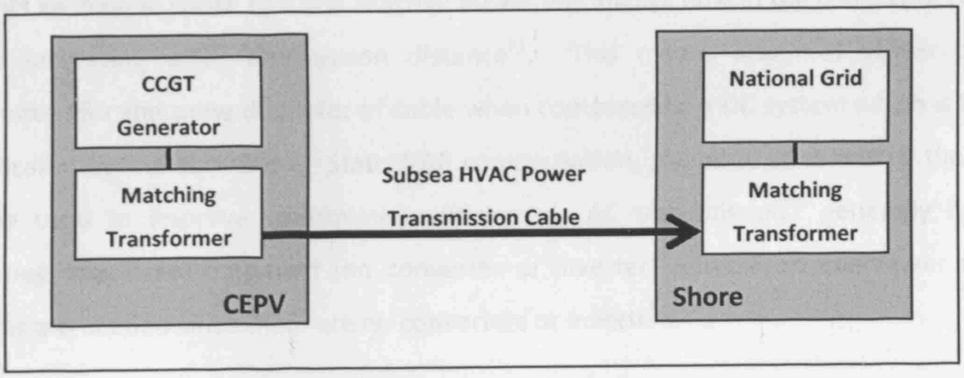


Figure 27 HVAC Transmission System

Subsea DC transmission systems are well established for long distance transmission for powers exceeding 100 MW at distances of up to 750 km[111]. DC transmission has the advantage that only real power is transmitted and fewer conductors are needed than for an equivalent AC system[112]. However, the main disadvantage of DC is the need for a converter to be located onboard the CEPV and an inverter to be located onshore. Additionally, the use of power converters necessitates the use of filters to remove unwanted harmonics in the electrical system so as to maintain acceptable AC waveform quality[113]. Power conversion technologies are considered in Appendix 3.

The proposed HVDC system for the Base Case CEPV is shown in Figure 28. In the proposed system a Voltage Source Converter (VSC) and Inverter (VSI) employing Pulse Width Modulation (PWM) technology is used primarily because of the high quality waveforms produced which minimise the need for large passive filters onboard the CEPV and ashore[114]. Internal arrangement for VSC and VSI is shown in Figure 29. VSC and VSI use insulated gate bipolar transistors (IGBT) or another similar fully controlled device. Fully controlled means that the device can be turned on and off by a control signal rather than by relying upon the power circuit's natural current reversal as would be required for the thyristor converter and inverter[114]. The HVDC system is arranged as a bipolar transmission system meaning that one conductor is at a positive potential and one conductor is at a negative potential. Current cable technology suggests bipolar voltages at 200 kV for a 250 MW transmission system would be feasible.

The proposed HVAC system for the Base Case CEPV is shown in Figure 30. Subsea AC transmission systems are used extensively for short transmission distances especially with offshore wind farms[115]. AC systems are disadvantaged by the need to supply charging currents each cycle hence real and reactive power will always flow in the cable with reactive power increasing with transmission distance[51]. This means less real power can be transmitted for the same diameter of cable when compared to a DC system which is further complicated by the skin effect. Static VAR compensation, placed at each end of the cable, can be used to improve transmission efficiency. AC transmission[51] generally has the advantage that less equipment (no converter or inverter) is required and fewer control systems are needed since there are no converters or inverters.

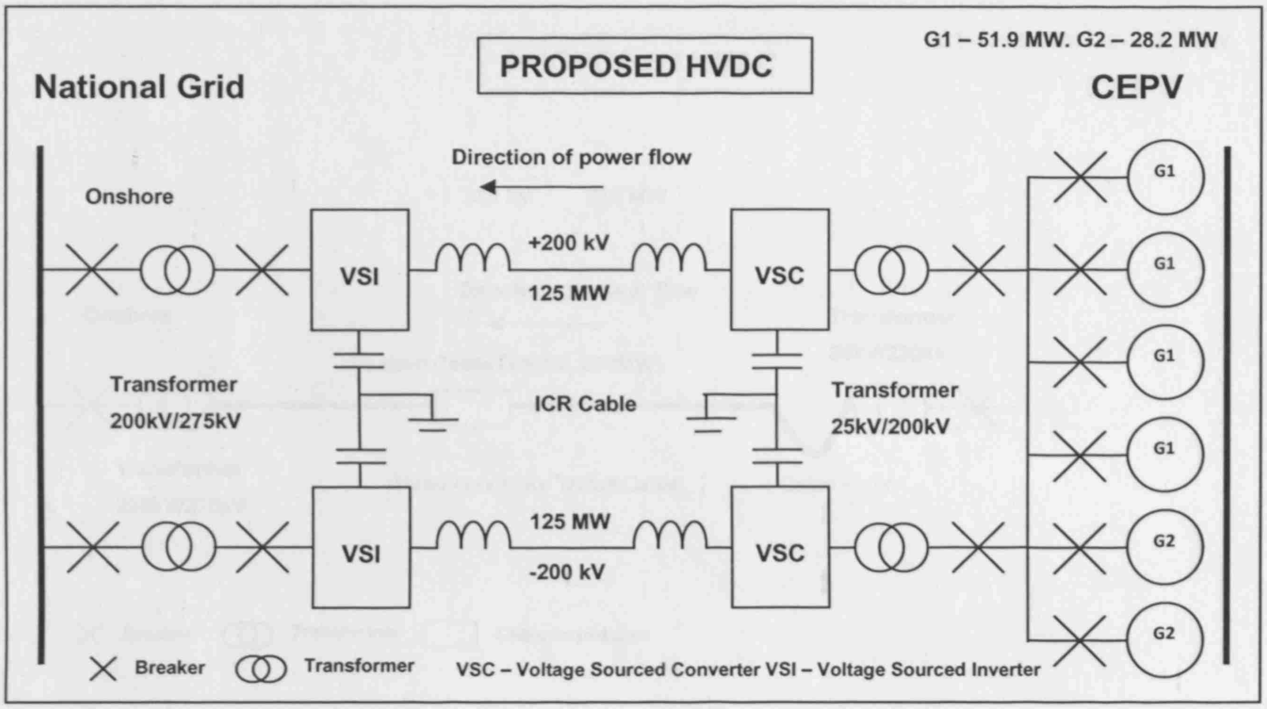


Figure 28 Proposed HVDC Converter and Inverter Arrangements for the CEPV

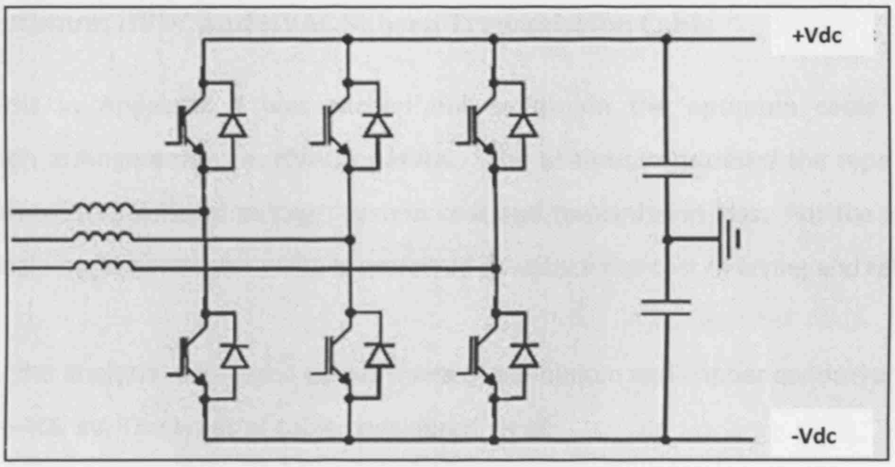


Figure 29 Internal Arrangement of the VSC and VSI for the HVDC System[116]

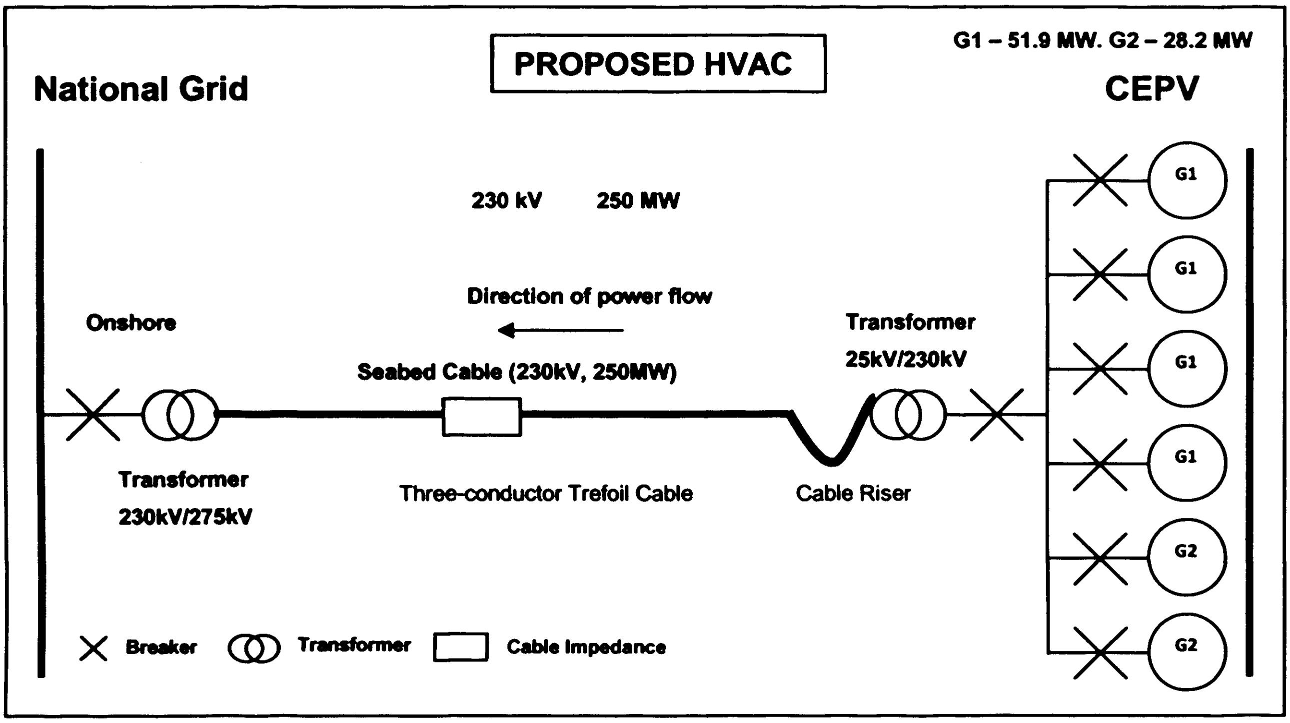


Figure 30 Proposed HVAC System for the CEPV

4.2.4 Optimum HVDC and HVAC Subsea Transmission Cable

The analysis in Appendix 4 was carried out to obtain the optimum cable for each transmission arrangements i.e. HVAC or HVDC. The analysis considered the type of cable, type of return, transmission voltage, system cost and transmission loss. For the HVAC and HVDC a single multi-conductor cable is preferred to reduce the cost of laying and retrieving.

For HVDC, the analysis considered cables made of aluminium and copper conductors ranging from 200 – 400 kV. The types of cable considered were:

- Single core cable with a sea return
- Single core cable with a metallic return
- Integrated conductor cable with two concentric conductors
- Møllerhøj cable having parallel conductors.

Figure 31 shows these different types of HVDC cables where the conductor, insulation, sheath and armour can be seen.

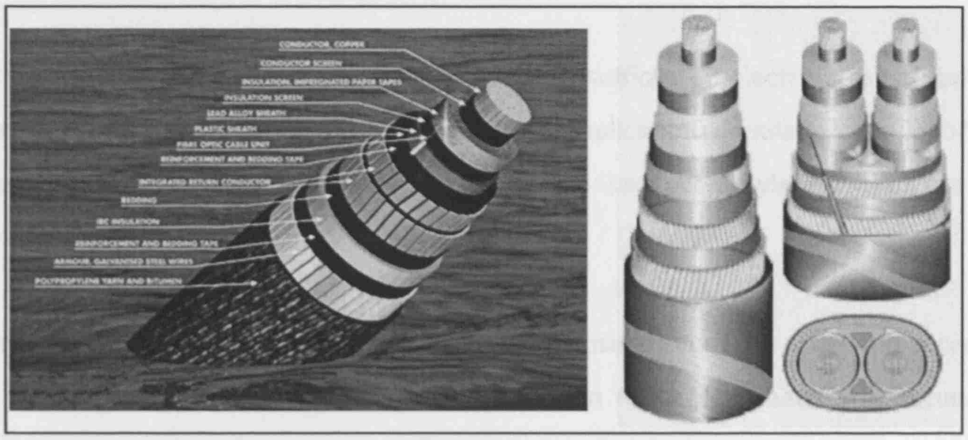


Figure 31 Nexans ICR Cable (Left)[117], Single Core Cable (Middle) and Møllerhøj[118] Cable (Right)

For HVAC cables need to have three conductors to carry the three-phase currents. For HVAC, the cables considered were:

- Three core cable in flat formation
- Three core cable in trefoil formation

Figure 32 shows these different types of HVAC cables where the conductor, insulation, sheath and armour can be seen.

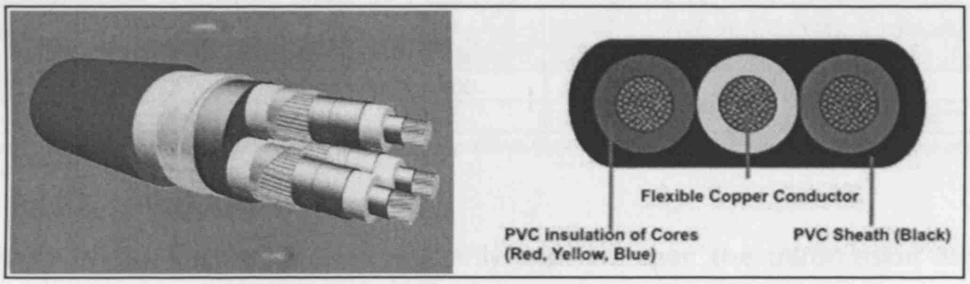


Figure 32 Three Core Cable in Trefoil[119] (Left) and Flat[120] (Right) Formation

The structure of each cable consists of a conductor layer, an insulation layer, a sheath and an armour layer. The purpose of these is discussed below.

Conductor – The conductor layer carries the current and consists of solid or stranded aluminum or copper. In DC cables the resistance is calculated as a function of cross sectional area, length of cable and temperature whilst for AC cables the calculation of resistance also takes into account skin and proximity effects, inductive and eddy currents in sheath, and eddy currents and reversal of polarity in armour[113].

Insulation – The insulation layer ensures that there is sufficient dielectric strength between the conductor and the sheath. For high voltage applications insulation made of mass impregnated non-draining paper (MIND) and cross-linked polyethylene (XLPE) are more commonly used.

Sheath – The purpose of the sheath is to protect the insulation of the cable and serves as a water-proof layer to the internal part of the cable. In AC cable Sheath Loss occurs from induced voltage resulting from magnetic field associated with AC current.

Armour – The armour layer protects the cable from interference from external activities such as fishing and provides tensile strength to the cable.

All the above cables were compared by considering type, voltage level, conductor material and size, insulation requirement, current return method, losses and converter requirements. The results are fully presented in Appendix 4 and the optimum cable choice for the HVAC and HVDC are summarised in Table 10.

Table 10 Optimum HVDC and HVAC Cables

Operation mode	Cable type	Voltage (kV)	Conductor material	Conductor CSA (mm^2)	Cost (£/m)	Losses (MW/km)	Converter cost (£)	Additional losses (%)
HVDC	ICR	200	aluminum	1000	142	0.051	50 M	5*
HVAC	Trefoil	230	copper	500	472	0.0969	n/a	5.14**

*This figure represents the converter losses. **This figure represents the reduction in power transmission capability of AC cable relating to distance.

The choice of transmission method primarily depends upon the transmission distance. HVAC is generally preferred for short distances whilst HVDC is generally preferred for longer distances driven by efficiency and cost. The cost differential is associated with the additional cost of the converters and inverters for the HVDC system compared with the additional losses that are incurred in HVAC transmission systems which will increase with distance. Typically the crossover distance is in the region of 50 – 80 km[121].

The following is a summary of the findings of the cable study:

- ICR cable with aluminium conductor is economically the optimum solution for the HVDC transmission system because aluminium is cheaper than copper by 65 %[122].

- Operational voltage in the HVDC transmission system should be kept as low as possible to minimise the conversion equipment cost but needs to be balanced against conductor size.
- Sea return for HVDC is not a viable solution when considering corrosion and environmental issues.
- For HVAC transmission system the trefoil formation cable offers a lower loss than for the flat formation.

4.3 Cable Riser Dynamics

4.3.1 Introduction

Subsea cable technology for the CEPV is available because subsea transmission systems both HVAC and HVDC are already in use and reasonably well understood for interconnecting shore-based National Grid networks e.g. 124 km 350 kV DC Skagerrak link[123] and 19 km 46 kV AC Belize link[51]. The CEPV arrangement differs in that the cable will need to rise from the seabed to the CEPV. This is an unusual and untried cable arrangement for a floating structure although flexible oil and gas risers would be used for fixed structures[124]. In this section of the thesis an investigation into developing a methodology for assessing fatigue in cable risers is presented. The developed methodology, which is considered to be novel, is primarily designed to establish the fatigue life of a cable and this is achieved by calculating the stresses in the cable riser between the vessel and the seabed.

A model for carrying out static analysis of the cable riser in a catenary profile is developed in Appendix 5. The behaviour of the constituents of the cable riser e.g. conductor and armour, under bending and tensile forces is established and used to interact with the cable profile to predict the stresses in the different parts of the cable riser as shown in Appendix 6. Environmental loads and the vessel response to these loads are then studied in a quasi-static analysis in Appendix 5. From these results the fatigue life of the cable can be predicted as shown in Appendix 7.

Whilst it is appreciated that seabed surface friction at tether point affects cable riser wear to a certain degree, as concluded by Triantafyllou et al, it has not been included in the discussion in this section simply because cable riser dynamics analysis in thesis was only intended as an exploratory study, contributing towards the aims of this research.

A detailed and more accurate analysis of cable dynamics would include investigation and prediction of dynamic tension in transient sea states and forces acting upon the cable by Vortex Induced Vibration (VIV). These analyses are beyond the scope of this thesis and are not included in the discussion. However, the magnitude of dynamic tension is estimated to be of lower order. Further work to investigate the effect of dynamic tension and VIV upon the cable riser has been suggested in Chapter Eight.

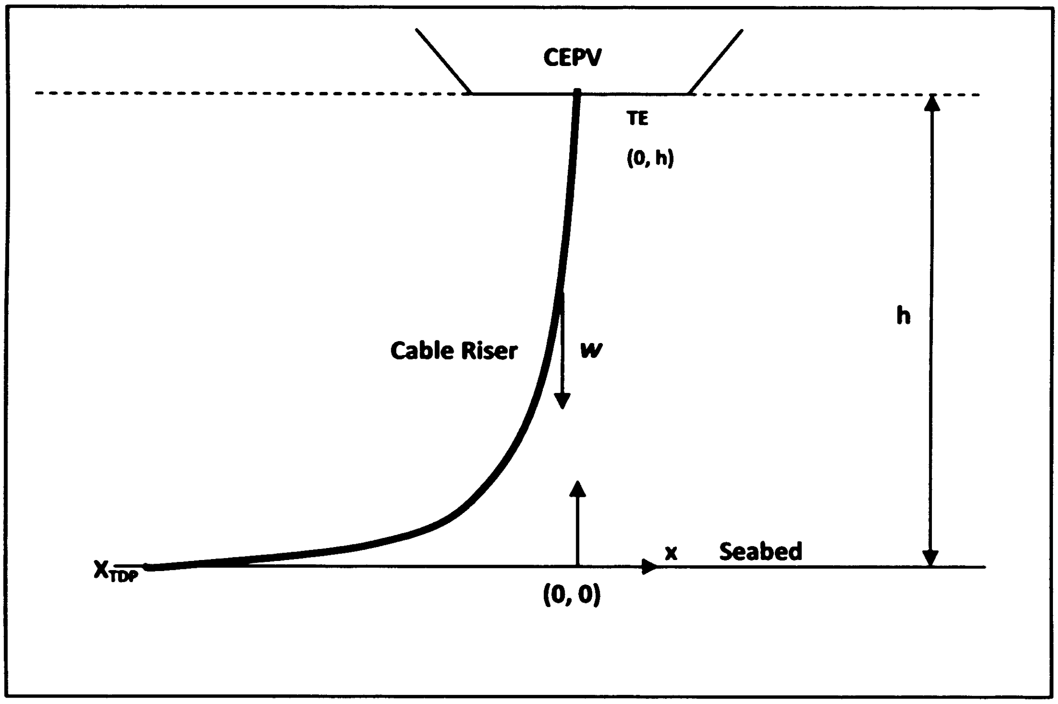


Figure 33 Cable Riser in Catenary Profile (E - Top End point, TDP - Touchdown Point, h - Water Depth)

Figure 33 shows a cable riser, which consists of a conductor, insulation and protection layers. The weight per unit length (w) of the cable suspended in sea water..is attached vertically at the Top End (TE) to the CEPV and is laid horizontally on the seabed at the Touchdown Point (TDP). This represents the two boundaries of the analysis.

4.3.2 Optimum Tension

The TE pre-tension applied to the cable riser governs the static behaviour of its catenary configuration and hence the curvature of the catenary profile. If the pre-tension is low the cable will have a large curvature and if it is too low then the cable is likely to buckle under its own weight due to high bending stresses in the vicinity of the curvature. If the TE pre-tension is high, the cable will be subject to high stresses (mainly axial) near the top. The tension level governs the dynamic behaviour of the cable since it determines its stiffness and its natural frequency. The selection of the optimal tension level is governed by several factors including cable parameters i.e. cable weight, environmental conditions and vessel operational characteristics which are all necessary inputs to determine the cable's static and dynamic behaviour and also its fatigue life.

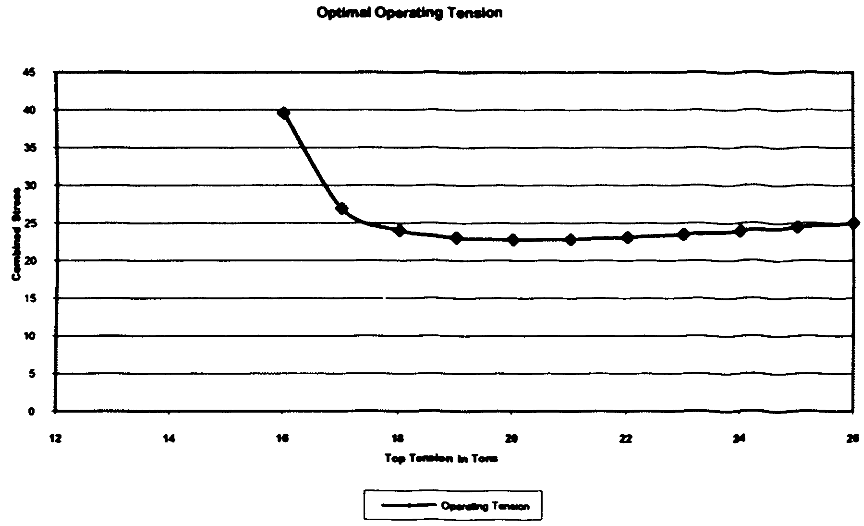


Figure 34 TE Pre-Tension Curve

By knowing the effective weight per unit length of the cable and the water depth, it is possible to estimate the optimum TE pre-tension level. Figure 34 shows that by varying the TE pre-tension it is possible to achieve the minimum combined stress in the core. This point is then taken to be the optimum tension level for all subsequent analyses. For low tension levels, high bending stress dominates the combined stress equation. This represents a slacking of the cable and a large curvature. For high tension levels axial stress dominates the combined stress equation. This represents a tightening of the cable and a small curvature. The optimum pre-tension level determined for a single core cable of 133 mm diameter using this method was 23 tonnes.

4.3.3 Models

A computer model has been developed to analyse cable stresses in a simple catenary arrangement. The computer model is based upon the theory first developed by Moe and Arnsten [125] which uses perturbation techniques and asymptotic solutions to predict the fatigue life. The computer model extends this theory to predict cable fatigue life and has been constructed in two parts namely static and quasi-static.

Static Analysis

The static analysis allows the axial stresses, the bending stresses at the vicinity of the TDP and the profile of the riser to be determined.

At this point, a maximum offset to account for vessel position (change in position of TE point) is introduced as a limit value for the static position. The offset is represented by two static positions which is a function of the initial static position and the water depth. The two new points frame the initial static configuration which gives the limit values of the stresses. The development of the equations for static analysis is given in Appendix 5.

Algorithm

A computer based model has been developed to calculate different tensions along the cable for a fixed water depth and TDP. The input parameters for this program are:

- water depth
- TDP
- the geometric parameter of the cable:
- diameters of the different layers
- modulus of elasticity
- Poisson ratio

Structure of the Model

A flowchart of the static model is shown in Figure 35. The first routine calculates the static configuration for an input water depth and an input XTDP. Therefore another routine, based upon the previous results calculates the tensions and stresses for the offset positions. A flowchart for this model is shown in Figure 36.

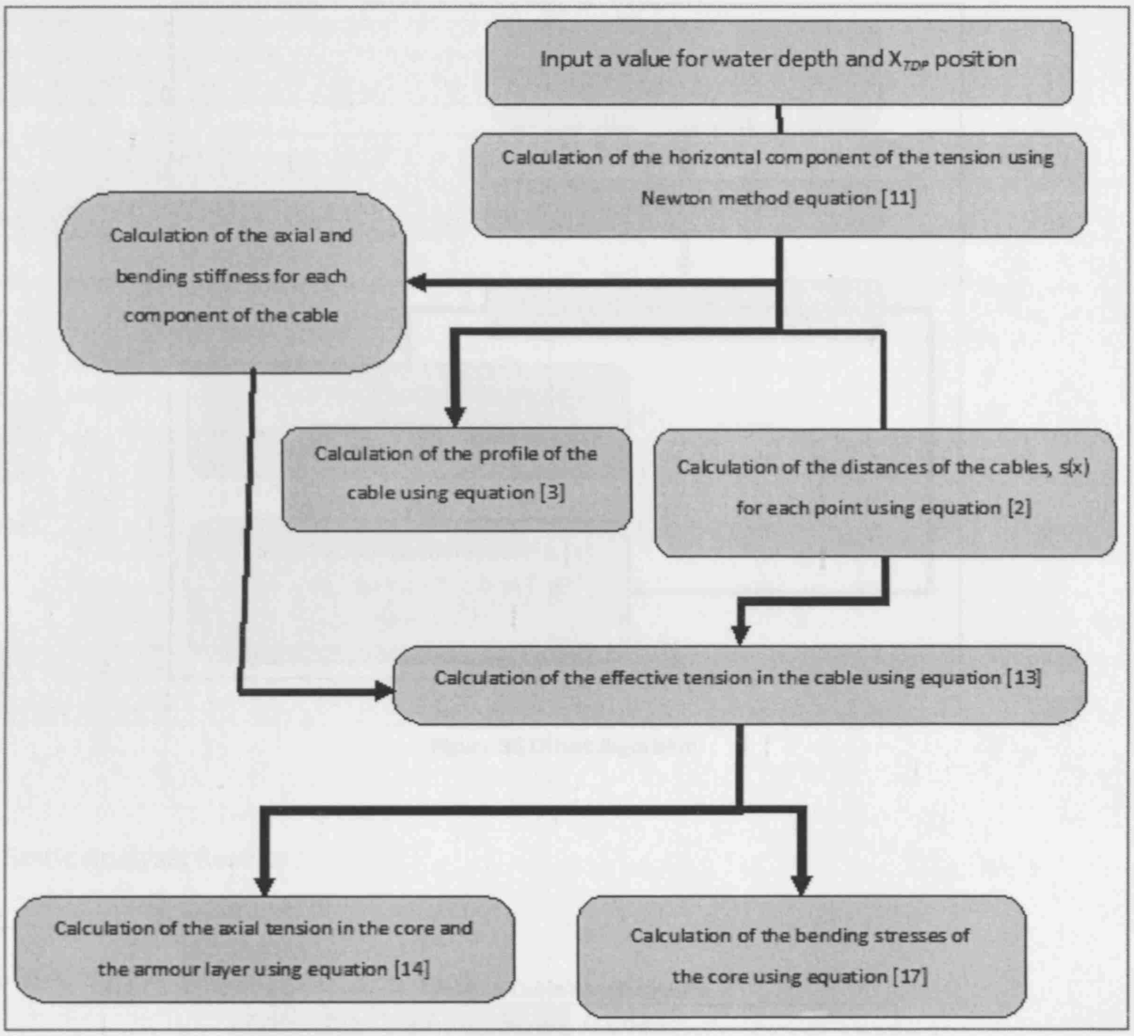


Figure 35 Static Evaluation Algorithm

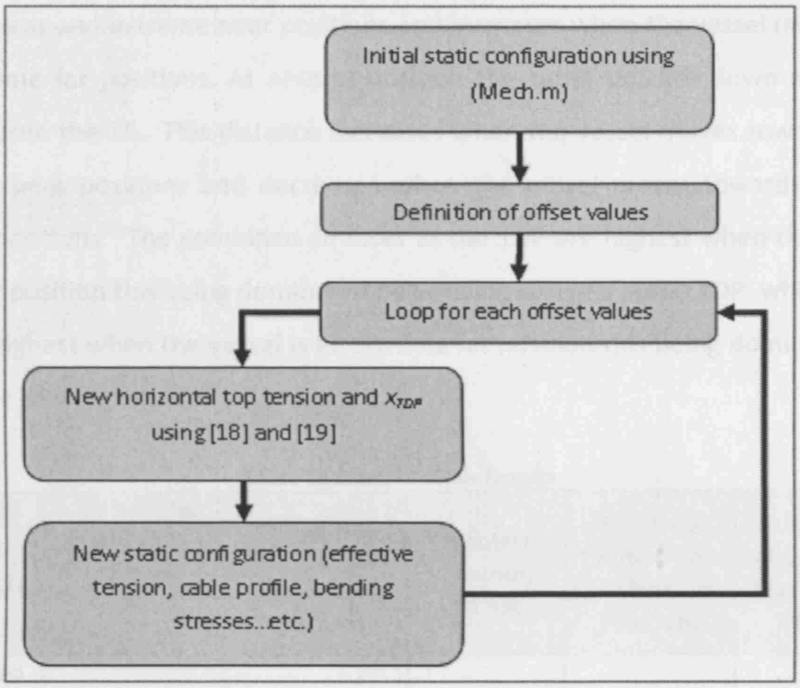


Figure 36 Offset Algorithm

Static Analysis Results

Table 11 Cable Specifications

Conductor Diameter (m)	0.0435
InsulationDiameter (m)	0.0435 (ID), 0.128 (OD)
Armour Diameter (m)	0.128 (ID), 0.113 (OD)

Table 11 shows the specification of the cable used in the analysis. The results shown in Table 12 and Figure 37 to Figure 39 were all generated using the computer models.

Table 12 shows the results from the static analysis of the cable described in Table 11. From the results it can be seen that four offsets 5 %, -5 %, 10 % and -10 % of the water depth have been considered to represent near, far, extreme near and extreme far positions of the vessel. ± 10% of water depth represent the worst case scenario e.g. heavy weather and with a broken mooring line; whilst the ± 5% of water depth offsets represents the normal operating envelope of the CEPV when using either a permanent mooring system or a dynamic positioning system.

The length of cable suspended at the neutral position i.e. no offset with a TE pre-tension of 23 tonnes is 650.4 m. The length of cable suspended decreases when the vessel moves towards the near and extreme near positions and increases when the vessel moves towards far and extreme far positions. At neutral position the cable touches down at –351.93 m horizontally from the TE. This distance increases when the vessel moves towards the near and extreme near positions and decreases when the vessel moves towards the far and extreme far positions. The combined stresses at the TDP are highest when the vessel is at extreme near position this being dominated by bending stresses at the TDP; whilst combined stresses are highest when the vessel is at extreme far position this being dominated by axial stresses at the TE.

Table 12 Static Analysis Results

Static Parameters	**-10 %Water Depth Offset (Extreme Near Position)**	**-5% Water Depth Offset (Near Position)**	**Neutral Position Offset**	**+5% Water Depth offset (Far Position)**	**+10% Water Depth Offset (Extreme Far Position)**
Suspended Length of Cable (m)	596.6	624.0	650.4	675.7	699.9
TDP (m)	-257.4	-307.2	-351.9	-392.6	-429.9
Maximum Combined Stress at Vicinity of TDP (MPa)	26.3	20.9	17.9	16.0	14.9
Maximum Combined Stress at TE (MPa)	11.0	11.7	12.4	13.1	13.7
Maximum Axial Stress at TE (MPa)	10.3	10.9	11.4	12.0	12.6
Maximum Bending Stress at Vicinity of TDP (MPa)	24.3	18.5	14.9	12.5	10.8
Maximum Bending Moment (Nm)	196.2	149.6	120.7	101.1	87.1
Angle at TE (º)	79.9	73.0	75.1	77.4	71.1

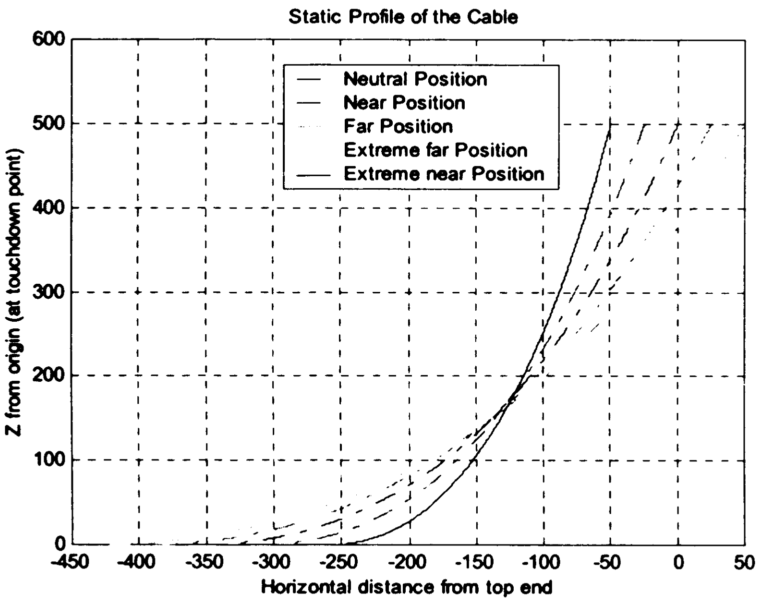


Figure 37 Static Profile of the Cable Riser

Figure 37 shows the static profile of the cable in a defined water depth. It can be seen that the cable forms a large curvature near the vicinity of the TDP when the vessel is at extreme near position and a small curvature when the vessel is at extreme far position.

Figure 38 shows the behaviour of the cable when the vessel is at neutral position i.e. zero offset. At neutral position the cable touches down at TDP at -351.9 m horizontally from the TE. In static analysis the term 'length along the cable' is used to represent the length of the suspended cable from the TDP. Axial stress is dominant at near TE and bending stress is dominant near TE.

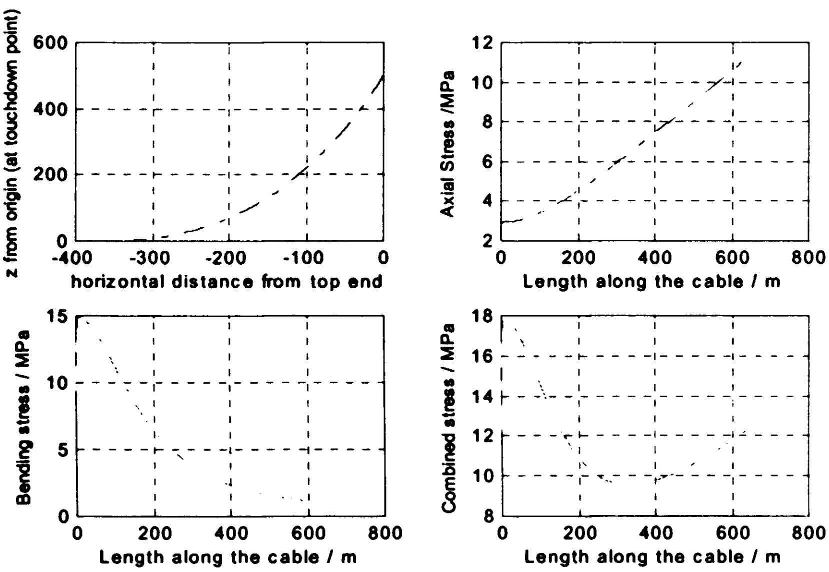


Figure 38 Static Analysis Results at Neutral Position

Combined stress along the cable for all offsets is shown in Figure 39. It can be seen that the cable suffers the highest bending stress when vessel is at extreme near position and lowest bending stress at extreme far position. For all offsets it can be seen that bending stress is highest near the TDP. Moving further away from the TDP axial stress starts dominating combined stress levels.

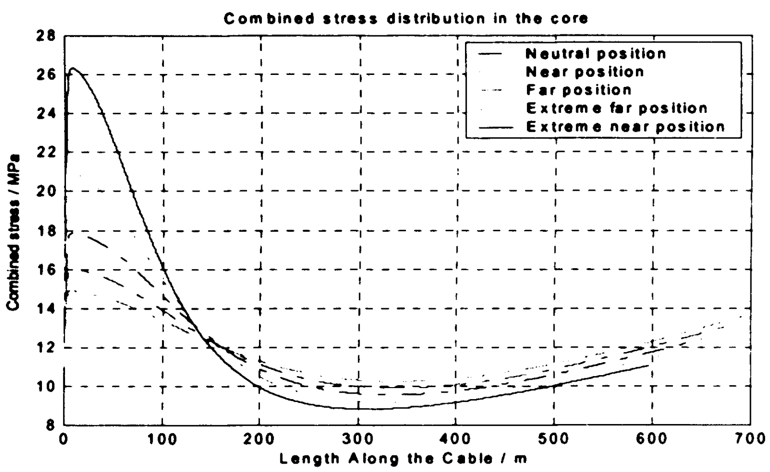


Figure 39 Combined Stresses along the Length of the Cable

Quasi-static Analysis

The quasi-static analysis is used to analyse second order motion which represents slower and larger lateral displacement of the CEPV between two points as a result of the forces of waves acting upon the CEPV in prevailing sea states. The second order motion represents the movement of the CEPV around a new position due to forces of the waves. The CEPV moves around this new neutral position with certain lateral amplitude between two positions: the Near-Near-Position (NNP) and the Near-Far-Position (NFP). This is shown in Figure 40.

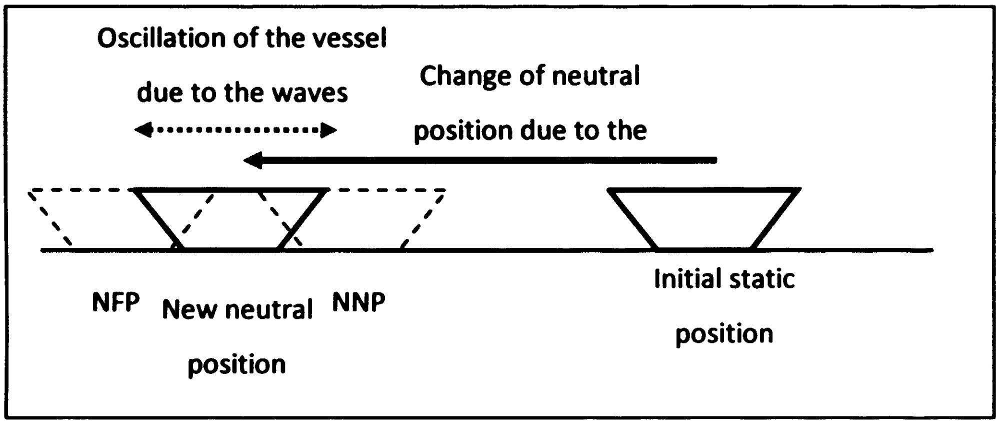


Figure 40 Second Order Motion

The quasi-static analysis is based upon the static analysis but it can represent the slow motion of the CEPV at the surface in most sea states. Limit offsets are used in the quasi-static analysis as a function of the sea state. There are two offsets defined for each sea state which represent the limit values of the position of the vessel for each sea state. In other words, in a certain sea state it is assumed that the CEPV position oscillates laterally between these two values. The development of the equations for quasi-static analysis is given in Appendix 5.

Algorithm

A computer based model has been developed to calculate the effective tensions and bending stresses for the different sea states using the quasi-static analysis. A flowchart of the model is shown in Figure 41.

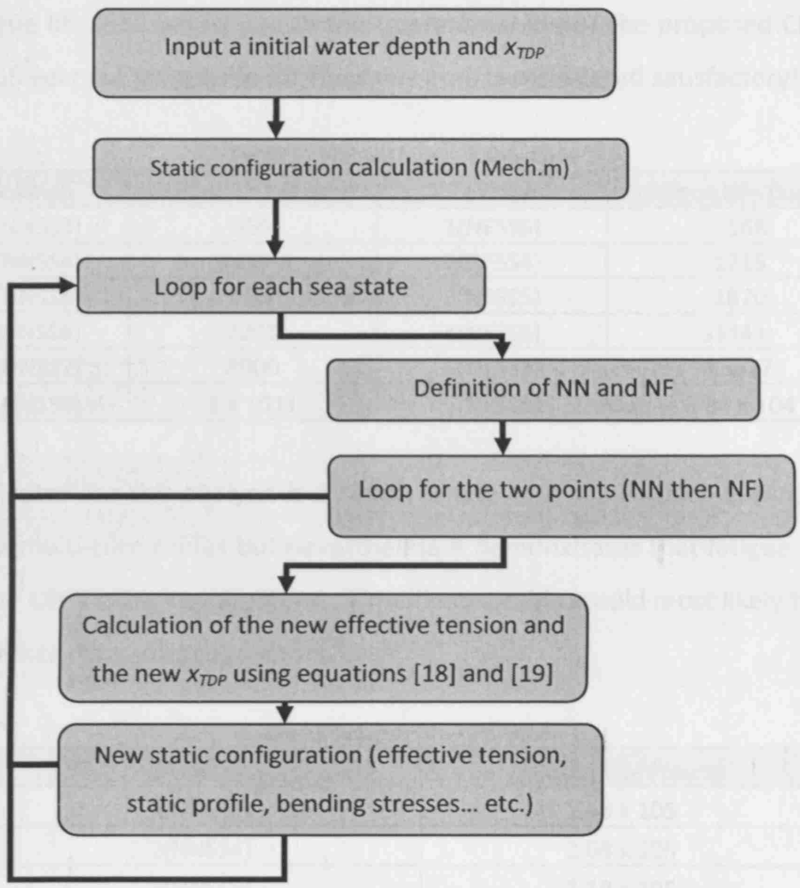


Figure 41 Second Order Motion Algorithm

Quasi-static Analysis Results

The results in Table 13 and Table 14 were all generated using the computer model and give predicted fatigue life of cable core and armour.

The results demonstrate that the fatigue life of the core is well beyond the operational life of the CEPV. It can also be seen that the core has shorter fatigue life than the armour.

Since fatigue in a marine environment involves variable amplitude loading as a result of random sea states represented by their probability of occurrence; fatigue life estimation has been further investigated using the cumulative damage approach.

The procedure for estimating fatigue life of the cable riser is done by independently assessing the fatigue life of the two critical components i.e. cable core and armour. The assessment of fatigue at the TDP for the quasi-static analysis shows that the core has the shortest fatigue life (355 years). With the operational life of the proposed CEPV set at 15 years then 355 years of fatigue life for the cable core is considered satisfactory!

Table 13 Fatigue Life of Cable Core

Position	Fatigue Life (Years)	Position	Fatigue Life (Years)
1(NNSS3)	355	1(NFSS3)	1568
2(NNSS4)	427	2(NFSS4)	1718
3(NNSS5)	729	3(NFSS5)	1870
4(NNSS6)	2298	4(NFSS6)	3441
5(NNSS7)	8000	5(NFSS7)	13627
6(NNSS8)	1 x 1011	6(NFSS8)	6.84 x 104

The cable selected for this analysis is a simple single core cable which is simpler to model than complex multi-core cables but nevertheless it demonstrates that fatigue life can easily be met for the CEPV cable requirement. A multi-core cable would most likely have stranded conductors rather than solid conductors[51].

Table 14 Fatigue Life of Armour

Position	Fatigue Life (Years)
1(NNSS3)	2.63 x 105
2(NNSS4)	2.68 x 105
3(NNSS5)	3.19 x 105
4(NNSS6)	3.76 x 106
5(NNSS7)	2.27 x 106
6(NNSS8)	9.97 x 106

The simplistic single core cable selected for this analysis consists of a solid conductor will have lower bending flexibility compared to a stranded conductor cable and a higher bending stress and a shorter fatigue life could reasonably be expected in a solid conductor cable rather than in a stranded conductor cable[125].

The ICR cable selected for the HVDC transmission and the Trefoil cable selected for the HVAC transmission are considered suitable as subsea transmission cables which can either be buried on the seabed to avoid damage from ground fishing or laid on the seabed to avoid the expense of burying and ease of recovery. If these cables cannot be manufactured for a dynamic riser then it is suggested that three single core riser cables are used for HVAC and two single core riser cables are used for HVDC. Connecting the riser cables to the transmission cables would require a connection box on the seafloor which could be located away from the TDP. The connection box would contain links from the riser cables and the transmission cable and could be immersed in oil to aid pressure compensation and cooling.

4.4 Summary

This chapter has focused on the electrical generation and transmission technology for the CEPV. Electrical generation on the CEPV is achieved with synchronous machines and the generated voltage is at 25 kV, this being considerably higher than the usual voltage levels generally found in marine vessels.

A HVDC transmission system and a HVAC transmission system have also been proposed for the CEPV. HVDC transmission systems are suited to long distances and require a converter on the CEPV and an inverter ashore and four types of cable are proposed with the preferred option being the ICR cable. HVAC transmission is more suited for shorter transmission distances and two types of cable are proposed with the Trefoil arrangement being the preferred option.

A methodology for the calculation of cable stress and the assessment of the cable riser's fatigue life has been presented. From the results it can be concluded that:

- A cable at the vicinity of the TDP was identified as the 'Hotspot' for occurrence of fatigue.
- The maximum bending stress in the core is in the vicinity of the TDP.
- The maximum axial stress in the core is at the TE.
- Preliminary assessment of fatigue at the TDP for the quasi-static analysis is that the core has a cable fatigue life exceeds the CEPV operational life.

The specification of the Base Case CEPV electrical system, as shown in Table 15 and Table 16, is carried forward to Chapter Five which considers the design and layout of the CEPV itself.

Table 15 Specification of the Base Case CEPV HVDC Electrical System

Equipment	Specifications	Manufacturer
Generators	6 x AC Synchronous Brushless Generators operating at 50 Hz and 25 kV: 4 x 61.1 MVA 2 x 33.2 MVA Volume : 2,506 m^3	GT Generators are supplied as part of Rolls Royce Trent package. ST Generators are supplied as part of Alstom steam turbines generator package.
Transformers	1 x Step-up Transformer on CEPV Volume : 630 m^3	Siemens Power Transmission and Distribution
Converters	VSC Converter/Inverter Volume : 13,000 m^3	ABB HVDC Light
Cable type	HVDC: 200 kV ICR Cable	ICR: Nexans Cables
Generator Circuit Breakers	Water-cooled, continuous current ratings up to 8,000 A Volume : 80 m^3	Hitachi GMCB SF6

Table 16 Specification of the Base Case CEPV HVAC Electrical System

Equipment	Specifications	Manufacturer
Generators	6 x AC Synchronous Brushless Generators operating at 50 Hz and 25 kV: 4 x 61.1 MVA 2 x 33.2 MVA Volume : 2,506 m^3	GT Generators are supplied as part of Rolls Royce Trent package. ST Generators are supplied as part of Alstom steam turbines generator package.
Transformers	1 x Step-up Transformer on CEPV Volume : 630 m^3	Siemens Power Transmission and Distribution
Cable type	HVAC: 230 kV Trefoil Cable	Trefoil: Alcatel Cables
Generator Circuit Breakers	Water-cooled, continuous current ratings up to 8,000 A Volume : 80 m^3	Hitachi GMCB SF6

5 Conceptual Design of the Base Case CEPV

5.1 Introduction

In the preceding two chapters, Chapter Three and Chapter Four, the equipment for a CEPV was identified with detailed studies focused on specifying items for the 'Base Case' CEPV. Chapter Three specified the power plant and by analysing the gas flow path for the gas turbines it was possible to specify the natural gas processing plant, the exhaust treatment plant and the CO_2 sequestration plant. Chapter Four considered electricity generation and defined the 'Base Case' electricity generating plant and the means to transmit electrical power by subsea cable to the National Grid. This Chapter is concerned with the design of the CEPV vessel needed to house the various equipment to meet the outline specifications discussed in Chapter Two.

A model for the Base Case CEPV is established using Initial Sizing. This model is then used in the sensitivity analysis to optimise vessel design in terms of size and cost given approximate estimates of the vessel components and systems. The methods employed in Initial Sizing and results are discussed in detail in Appendix 8.

A Parametric Survey of available models yields an optimum vessel design and arrangement given the required generating capacity. Having chosen the gas turbines plant for electrical power generation and the general layout, the hull form will then be sized accordingly to ensure good seakeeping characteristics of the vessel. An optimum design is then chosen using design evaluation matrix. The Parametric Survey is explained in Appendix 9.

In addition to housing the equipment identified in the previous chapters, the CEPV needs to have the capability to operate at maximum output for most of the year with minimal down time in order to maximise its economic competitiveness. In addition, to all the usual facilities found on offshore vessels, facilities to allow the vessel to maintain a specific weather heading and location over the seabed are needed. The vessel must also provide facilities to support the CEPV crew and in particular to address safety issues and meet appropriate regulation. Appropriate helicopter and mooring facilities are needed to provide for crew changes and replenishment and also to offload condensates and any fluid and solid waste.

The conceptual design of the vessel has been done in two parts. Firstly, the most suitable type of vessel for the 'Base Case' CEPV design was established and research work led to establishing a conceptual design from which the Single Sheet Characteristics were established together with an initial look at Vessel Layout. Different types of offshore platforms and vessels are considered as possible solutions for the CEPV and selection has been made after due deliberation by considering the advantages and disadvantages of all types of hull form and platform options using design evaluation matrix.

The second part was to establish an appropriate algorithm that would allow the 'Base Case' vessel to be scaled appropriately so as to allow other power plants, as identified in Chapter three, to be incorporated together with their scaled processing equipment. This is to allow appropriate costing algorithms to be developed for the Economic Model developed in the next Chapter. Costing the CEPV is very important since the Unit Production Cost (UPC) and Through Life Cost (TLC) is important to establish the overall economic viability.

5.2 CEPV Requirements

The design of the CEPV is primarily driven by the volume needed to house the equipment. The specifications of the main equipment were identified in the earlier Chapters and are summarised again for convenience together with new items to support the CEPV and crew.

5.2.1 Key Equipments

The Key Equipment consists of all the equipment needed to allow the generation of electricity from a stranded natural gas reserve including the natural gas processing plant, the electricity generating plant, the exhaust gas processing plant and CO_2 sequestration plant and also the CEPV end of the electrical transmission system:

Table 17 Key Gas Flow Equipment for a 'Base Case' CEPV Extracted from Table 17 in Chapter Three

Equipment	Volume
Power Generating Plant	11,713 m^3 – Power Plant only
Gas processing plant	13,500 m^3
CO_2 capture and sequestration plant	274,725 m^3
Turret	3,534 m^3

Important design issues associated with the Key Equipment which impact the design of the vessel are:

- The gas turbine exhaust must be arranged to allow the fitting of two WHRUs in a parallel configuration.
- The steam plant needs to be located near the gas turbine exhaust uptake waste heat recovery unit to minimise excessive piping requirements.
- The gas processing plant must be located in a different compartment from the generating plant for safety reasons and should be well ventilated. Deck operations can be considered.
- The arrangement for the Natural Gas processing onboard the CEPV must be such that a minimal risk of leakage gas accumulating in compartments.
- CO_2 sequestration plant must be located near the gas turbine exhaust path to minimise excessive piping requirements.
- Appropriate maintenance envelopes need to be applied in the machinery spaces to allow for maintenance work and inspection

Table 18 Key Electrical Equipment for a 'Base Case' CEPV Extracted from Table 4.6 in Chapter Four

Equipment	Volume
Generators	2,506 m3
Switchgear/Breakers	80 m3
Transformers	630 m3
Converter	13,000 m3
Switchboard and Distribution Systems	56 m3

Important issues associated with the Key Electrical Equipment upon the design of the vessel are:

- High voltage equipment e.g. circuit breaker, transformer and converter are to be located in an isolated compartments where only trained and certified personnel are allowed to operate and perform maintenance. These spaces would generally be unmanned and monitored by CCTV from the Central Control Room.
- Each gas turbine and steam turbine generators are to be separated into different compartments with appropriate switchgear and protections systems located close to each set i.e. modular arrangement to allow shut down and isolation of part of the electricity generating plant.

- The cable riser arrangement should not impede the vessels operational arrangement.

5.2.2 Ship Equipment

In addition to the key equipment above additional equipment will be required on the vessel to allow the vessel to operate as intended:

Table 19 Ship Equipment for a 'Base Case' CEPV

Equipment	Comment
Dynamic Positioning System	The use of a minimum of four variable speed thrusters with control system located in the Central Control Room. The thrusters would need to be sized to cope with weather conditions up to sea state 6.
Auxiliary Diesel Generators	The electricity use onboard the vessel would be extracted from the electricity generating plant. For the case of loss of power or start up then there needs to be a facility to obtain power from an auxiliary source. Diesel generators are considered appropriate for this role using marine diesel oil.
Seawater plant	Significant levels of seawater will be needed for cooling in the CEPV processing plant. A dedicated seawater system is envisaged that would have 100% redundancy capability and allow seawater draw from either side of the vessel.
Fire fighting	The ship's crew is small and therefore the ability to fight fires is impaired. It is envisaged that fixed fire fighting systems will be installed. This would allow inert gas injection into machinery spaces and electrical equipment spaces.

Important issues associated with Ship Equipment upon the design of the vessel are:

- The dynamic positioning system will need to maintain the vessel's weather heading and position over the seabed at all times and hence a dual redundant system is needed.
- Auxiliary diesel generators need to be located away from the main electricity generating plant where they are easily accessible.
- Fire detection and fire fighting systems should be as automatic as possible.

- Wide use of CCTV is considered essential to monitor the machinery space

5.2.3 Crew Equipment

The CEPV will operate 24 hour a day and 359 days a year i.e. six days are envisaged for planned and unplanned maintenance which is similar to most offshore installations[126]. It is envisaged that the CEPV would normally require 20 crew members with 10 being the Ship's Crew and 10 being the Plant Engineering Crew.

Table 20 Accommodation Requirements for the 'Base Case' CEPV

Space	Comment
Accommodation	The accommodation would be to a high standard with individual space consisting of a large cabin and bathroom. The Master and Chief Engineer would also have a Day Room.
Messing	There would be a single-self service canteen with officers and crew messing together. Common spaces for entertainment will be provided.
Offices and Meeting Rooms	Office space would be provided for the Master and the Chief Engineer. There would also be one meeting room.
Galley and Laundry space	Common facilities will be provided.
Stores	Cold rooms for meat, fish, vegetables and diary products will be provided. Dry goods rooms are also to be provided. Stores capacity for 3 months will be provided for
Sewage Treatment Plant and Tank	Sewage processing units are required to treat 'black' and 'grey' water for the vessels complement. In case of failure of this plant a tank is required.

The Ship's Crew would be headed by a Master and consist of four officers, covering deck and ship's own engineering duties, with the remainder being able seaman. There would also be a cook. The Plant Engineering crew would be headed by a Chief Engineer and consist of technical and operations staff. The CEPV crew would work shifts whilst working and two crews would rotate on two weekly rotas. Such manning arrangements are typical of offshore platform practice[126]. The crew allocation decided for the CEPV is based upon standard industrial practice on offshore exploration facilities[127].

Table 20 explains the design philosophy for the CEPV

Important issues associated with the crew requirements upon the design of the vessel are:

- Accommodation block is to be located away from the electricity, gas processing and CO_2 sequestration plant and to be protected against gas fires and explosions. Its location must allow ease of evacuation e.g. lifeboat and helipad facilities must be local.
- An emergency escape is to be provided for crew evacuation from the accommodation block to a temporary refuge area (in case of fire in the accommodation) to allow evacuation by helicopter and life boat.
- Accommodation block and helicopter landing platforms are to be located as far away as possible from the emergency flare for safety reasons.

5.2.4 Tankage Requirements

Tankage requirement for the operation of the CEPV is shown in Table 5.5.

Table 21 Tankage Requirements for a 'Base Case' CEPV

Tanks	Volume
Natural Gas Condensates	1,000 m3
Sludge and waste oils	250 m3
Water. Potable and Steam Plant	400 m3
Natural Gas Buffer	900 m3
Marine Diesel Fuel	4000 m3

Important issues associated with the tankage requirements upon the design of the vessel are:

- A space is to be allocated above the tanks for maintenance work, access and inspection
- Natural Gas Buffer (vessel) is to be included in volumetric allocation for the gas processing plant
- The tanks are to be considered alongside 'heavy machinery' when considering the vessel's weight distribution.

5.3 Vessel Type

There are a considerable number of hullforms and platforms but after considerable deliberation of the CEPV requirements the choice reduced to the Tension Legged Platform, Semi-submersibles, and the Floating Platform Storage Offshore. These are now viewed by considering their advantages and disadvantages below.

5.3.1 Tension-Leg Platforms (TLPs)

TLPs are floating structures where the mooring system is constituted by vertical tethers. This characteristic makes the structure very rigid in the vertical direction and flexible in the horizontal plane[127]. The vertical rigidity is beneficial for securing to wells for production whilst the horizontal flexibility makes the platform insensitive to the effects of waves. A typical TLP consists of a concrete hull and a steel deck as shown in Figure 42.

Figure 42 Tension Leg Platform[128]

Key Advantages

- Proven ability to operate with riser pipelines and electrical cables
- Has large deck area
- Can sit on the seabed hence no dynamic positioning system is needed

Key Disadvantages

- Sensitive to weight distribution
- Does not have significant onboard storage facilities (tankage)
- Does not allow ease of relocation from field to field

5.3.2 Semi-Submersibles

Semi-submersible drilling platforms are used in open water e.g. the Gulf of Alaska and the Bering Sea[129]. These platforms are capable of operating in deep water in heavy seas. These structures are called semi-submersibles because their legs are flooded with water for extra stability in the open ocean. Semi-submersibles float on water and utilise a series of anchors and winches to maintain their position[130]. Semi-submersibles are similar to a TLP because it consists of a concrete hull and a steel deck. Figure 43 shows a typical semi-submersible.

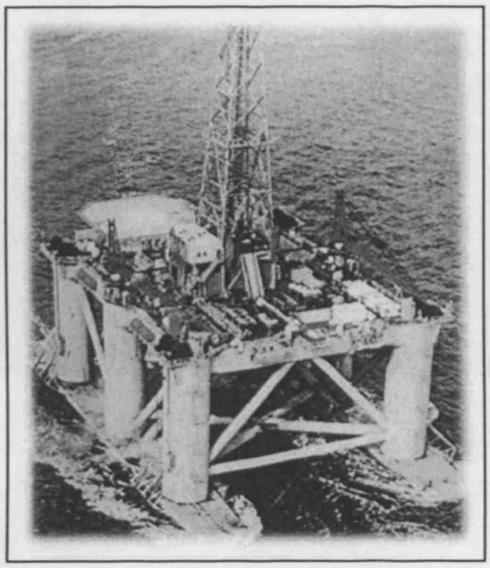


Figure 43 Semi-submersible[131]

Key Advantages

- Good motion characteristics
- Proven ability to operate in deep water
- Has large deck area

Key Disadvantages

- High construction cost compared to other vessels
- Requires DP System
- Lack of internal space

5.3.3 Floating Production Storage and Offloading Vessel (FPSO)

An FPSO is an offshore exploration facility housed in a monohull vessel. It is designed to provide operational flexibility in the offshore environment. The FPSO has the capability to explore marginal oil and gas fields in areas where harsh weather conditions are prevalent as well as shallow benign areas in a cost-effective way[132]. The FPSO has so far been used primarily for oil production but other applications have also been considered. Figure 5.3 shows a typical FPSO.

Figure 44 FPSO[133]

Key advantages

- Suitable for remote locations without or with minimal existing infrastructure
- Oil or gas storage is provided as an integral part of the vessel hull
- The FPSO is designed for relocation and may be re-used in other fields

Key Disadvantages

- Needs dynamic positioning system
- Rigid risers not feasible
- Sea keeping performance poorer

5.3.4 Chosen Option

Table 22 Design Evaluation Matrix for Vessel Selection

Criteria	Weight	TLP		Semisub		FPSO	
		Score	Weighted Score	Score	Weighted Score	Score	Weighted Score
Vertical flexibility	5	6	30	4	20	7	35
Horizontal flexibility	4	6	24	6	24	6	24
Large deck area	5	7	35	7	35	6	30
In-hull storage	8	4	32	4	32	8	64
Operating in deep water	6	3	18	7	42	8	48
Operating in heavy sea	8	6	48	7	56	7	56
Good motion characteristics	5	8	40	8	40	6	30
Suitable for remote locations	9	5	45	6	54	7	63
Requires minimal infrastructure	9	4	36	5	45	6	54
Easy relocation	8	3	24	5	40	8	64
Total Score			**332**		**388**		**468**

At this point it is important to say that any of the above vessels has the potential to be converted to become a CEPV. By examining the advantages and disadvantages of the above options, evaluated using a Design Evaluation Matrix in Table 22 Design Evaluation Matrix for Vessel Selection, it is perhaps reasonable to suggest that the FPSO is probably the most viable solution for the CEPV considering the experience already gained in the CEPV's intended area of operation in the North Sea[134]. The FPSO is seen as a robust and cheap to construct solution to explore small or marginal gas fields in harsh weather conditions; and has the added advantage of its flexibility to relocate to other gas fields with minimal installation work.

5.4 The Solution

5.4.1 Ship Design Process

The ship design process was achieved using several methods. Whilst the selection of the gas turbine plant was driven by plant efficiency and design evaluation matrix discussed in Chapter Three; the overall design of the Base Case CEPV was achieved using a volumetric approach, commonly applied in the ship building industry. This is because the spaces occupied by the machinery e.g. natural gas processing plant, electricity generating plant and converter is likely to weigh less than similar space occupied by cargo onboard merchant vessels e.g. tankers. Balancing the total volume required with total volume available determines the optimum vessel dimensions. This method is further explained in Appendix 8.

The conceptual design of the CEPV is achieved using a total vessel design methodology. This means that the vessel size and machinery requirements and design layout are considered equally. Having established the outline requirements a parametric survey of different outline designs were considered. The selection of the Base Case CEPV for further study considered facilities and layout onboard including machinery space and accommodation and safety. The Parametric survey has been considered in Appendix 9.

A single sheet characteristic of the CEPV is shown in Table 23 and a Profile of the final layout of the CEPV is shown in Figure 5.4.

In Table 23, it can be seen that the CEPV's length overall is 185 m and has a deep displacement and lightship displacement are approximately 67,000 tonnes and 62,000 tonnes respectively. Unlike a conventional FPSO where there is a large difference between deep and lightship displacements because of the difference in tonnage allocated for cargo; the small difference between both displacements for the CEPV are accounted for onboard fluids e.g. condensates, water, marine diesel fuel, and stores.

Table 23 Single Sheet Characteristics of the CEPV

Clean Energy Producing Vessel			
Role	To import raw natural gas natural gas from wellhead, to prepare and condition natural gas for CCGT plant for generation of electricity for export; to extract valuable condensates from raw natural gas for export; to capture and sequestrate greenhouse gases generated.		
Ship features			
Deep displacement	67,037 tonnes	Light ship displacement	62,026 tonnes
Length (BP)	179 m	Length (OA)	185 m
Beam (WL)	34 m	Depth of hull	19 m
C_p	0.86	C_m	0.98
Stores	30 days maximum	Complement	20
Operational area	North Sea	Hull type	Mono-hull
Payload			
Gas processing plant		CO_2 sequestration plant	
Gas turbine and steam turbine generators		Submerged turret production system	
Machinery			
Gas processing plant	Electricity generating plant	Electrical equipment	Other
3-phase separator Amine gas sweetener Glycol dehydration unit Gas compressor	4x Rolls Royce Trent gas turbines and generator 2x Alstom WHRU steam turbine and generator 4x Wartsila diesel generators	1x Siemens power transformer 1x Siemens switchgear 1x Hitachi GMCB SF6 circuit breaker 1x ABB HVDC Light converter station	1x APL submerged turret production unit 1x condensate offloading facility
Tankage			
Condensate	1,000 m^3	Sludge and waste oils	250 m^3
Fresh Water	400 m^3	Natural gas buffer	900 m^3
Diesel	4000 m^3		

5.4.2 Vessel Features

The Base Case CEPV design has features and internal arrangements to meet all the above requirements. These features and arrangements are now explained below.

Main Features

In Figure 45 it can be seen that the electricity generating plant is located aft of amidships to give an even longitudinal weight distribution when also considering the gas processing plant, swivel turret and accommodation block. An even transverse weight distribution is also achieved with the gas turbine arrangement as seen in Figure 49. All high voltage equipment such as rectifier unit and transformers are located at the aft of the CEPV in isolated compartments. The gas processing plant is located on the Upper Deck just above the turret unit to minimise piping requirements for raw natural gas import from the swivel turret. The Central Control Room is located in the accommodation block where the gas processing plant, electricity generating plant, turret unit and electrical equipment can be monitored remotely.

In Figure 46it can be seen that three cranes are provided on the upper deck. Exhaust funnels are located amidships away from the accommodation block. Emergency flare is located at the stern of the CEPV so as to minimise fumes penetrating the accommodation block. The auxiliary diesel generators are located on the Upper Deck for easy access in the event of an emergency. An escape tunnel from the accommodation block at the bow is provided to facilitate an escape route for the crew members to the temporary refuge area at the stern of the CEPV where a second helipad is provided for emergency evacuation together with life boats.

In Figure 49, it can be seen that the gas turbines are split into two banks i.e. port and starboard units. In each bank two gas turbine generators are connected to a WHRU and a steam turbine generator. These are to be referred to as Port Generators and Starboard Generators. These prime-movers and generators are considered as 'heavy machinery' and are placed as low as possible to the keel to provide stability to the CEPV

Tankage

In Figure 47 it can be seen that a space is allocated above fluid tanks for inspections and maintenance work. Stairs are provided for access from accommodation block to machinery space on Lower Decks 1 - 3. The turret unit can be accessed from this deck or the deck below for maintenance work. The WHRU, which stands over Lower Decks 1 and 2 can also be accessed from this deck for maintenance work. In Figure 48 it can be seen that fresh water and distilled water tanks, diesel tanks, condensates tank and crude oil tank is provided over Lower Decks 2 and 3. These tanks form part of the CEPV's longitudinal weight distribution and are placed as low as possible to the keel to provide stability for the CEPV.

Water Ballast

Ballast pumps and tanks are provided in the port and starboard bulkheads as part of the CEPV's anti-rolling mechanism. Port and Starboard ballast tanks are connected using a pipe and ballast pumps are provided on each side to transfer ballast water from one tank on one side of the vessel to the other to counter the vessels rolling motion in excessive sea states. The size of the ballast tanks are estimated to be 24 % of the main hull volume justified by the average volume of ballast tanks on conventional FPSOs to be 20 – 29 % of main hull volume[135].

Vessel and Crew Safety

The CEPV's safety system is designed such that safety of the crew members and operation is ensured. The safety equipment and apparatus provided on the CEPV includes:

- Life saving appliances e.g. Breathing apparatus and lifejackets would be provided throughout the vessel including in the accommodation and machinery spaces.
- Two lifeboats at the bow and one lifeboat at the stern of the vessel for crew evacuations.
- Escape tunnel that connects the accommodation block to the temporary refuge area at the stern of the CEPV.
- Fire protection and extinguishing system would be provided in accommodation block and machinery space.
- Fixed fire fighting facilities include foam and inert gas drench systems.
- Portable Fire Extinguishers would be provided in accommodation block and machinery space.
- Fire pumps for using sea water located at the stern and bow.
- Gas detectors for detecting gas leakage.
- Temporary refuge area is provided at the aft of the CEPV away from the accommodation area. This is situated next to the second helideck provided to give an alternative means of evacuating the vessel in the case of an emergency.

The above would exceed SOLAS regulations for safety of life at sea.

Swivel Turret

An STP swiwel turret is provided near the bow of the CEPV. The turret is located under the gas processing plant so as to minimise excessive piping. The turret is arranged in the hull where structural support to the turret and accessibility for maintenance are provided. The swivel exports natural gas from the wellhead via an up-pipe and exports CO_2 to depleted oil and gas field for sequestration. The swivel turret also exports the generated electricity to a cable riser where it is sold into the National Grid ashore via a subsea cable. The swivel turret is connected to the high voltage electrical equipment located at the stern of the CEPV. A cable duct is provided above the keel from aft of the CEPV to the turret unit for electricity export via the swivel turret. Export of generated electricity from the CEPV via the power swivel is possible by upgrading existing high voltage power swivel elements[136].

DP System

The CEPV's station keeping can be kept by using a DP System especially in deeper water where permanent mooring is not sufficient. The DP System will consist of a minimum of four variable speed thrusters with control system located in the Central Control Room. Two thrusters would b placed at the bow and stern of the CEPV. Each of these thrusters are rated at 3 MW, which is the minimum power required for the CEPV to cope with heavy weather conditions in high sea states.

Mooring

Mooring of stores and marine diesel fuel supply vessel and shuttle tankers for condensate export will be provided by vessel mooring system which consists of a mooring winch along the longitudinal sides of the CEPV. A minimum of two mooring winches would be required on each sides of the vessel.

When the CEPV is operating in shallow water (less than 300 m) station keeping could be provided by permanent mooring onto the STP swivel turret thereby providing passive weather vaning of the CEPV by securing the CEPV onto the seabed. In such cases the DP System thrusters could be switched off.

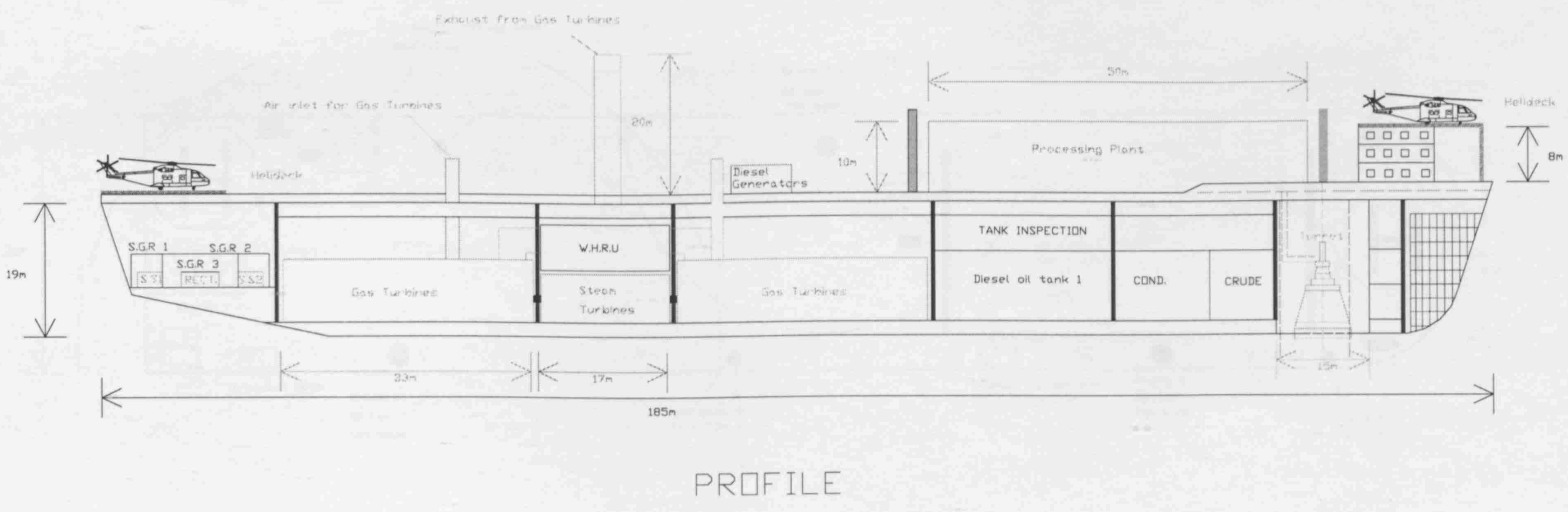


Figure 45 Profile of the CEPV

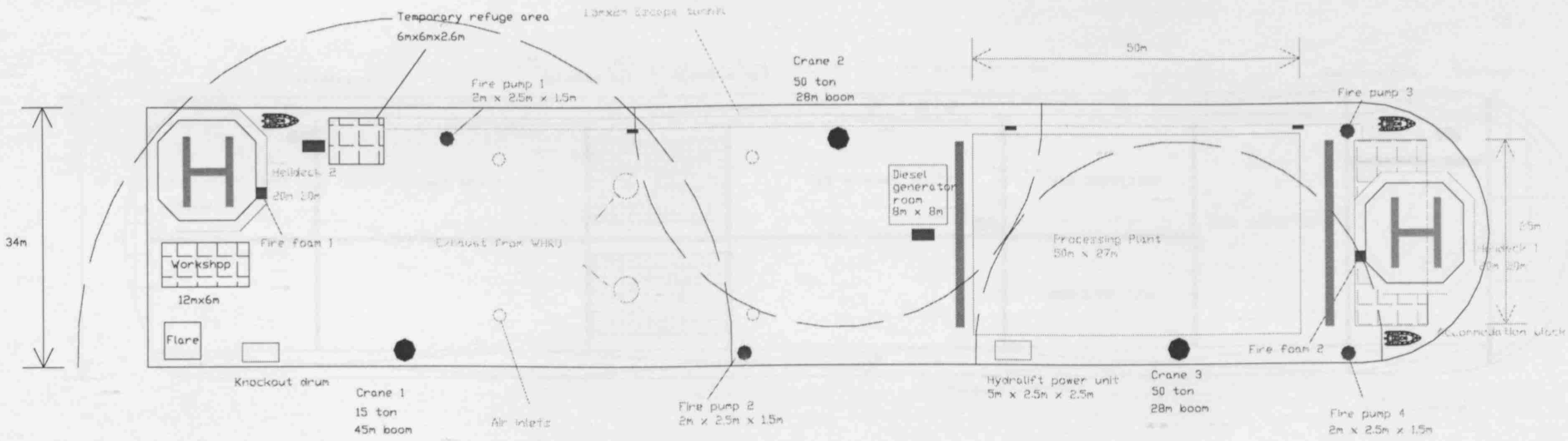


Figure 46 Upper Deck Layout

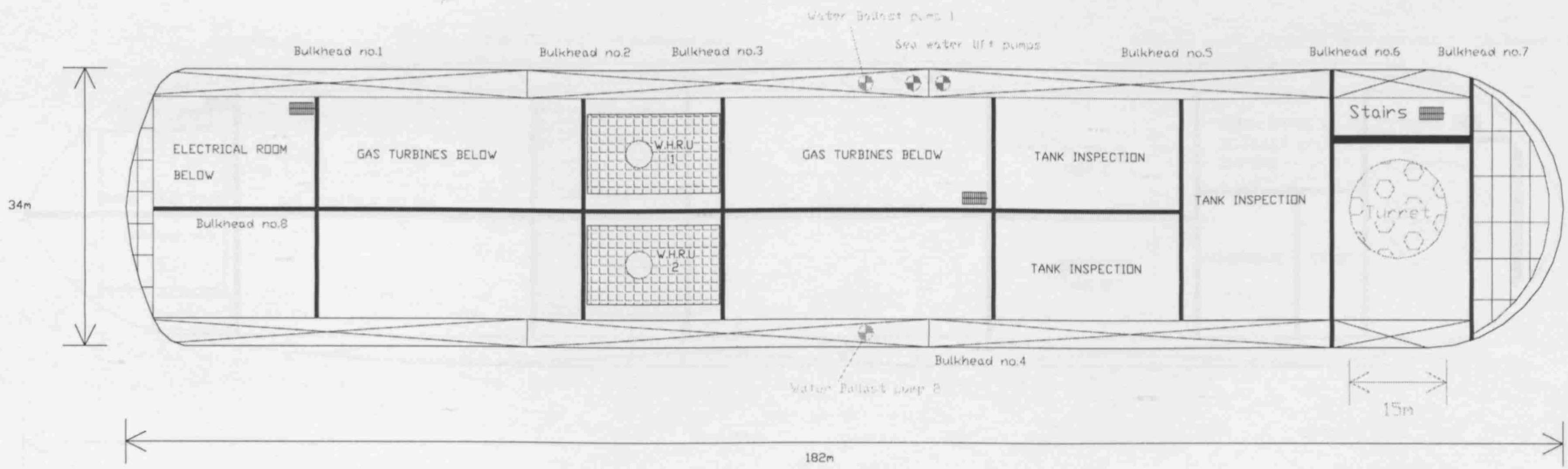


Figure 47 Lower Deck 1 Layout

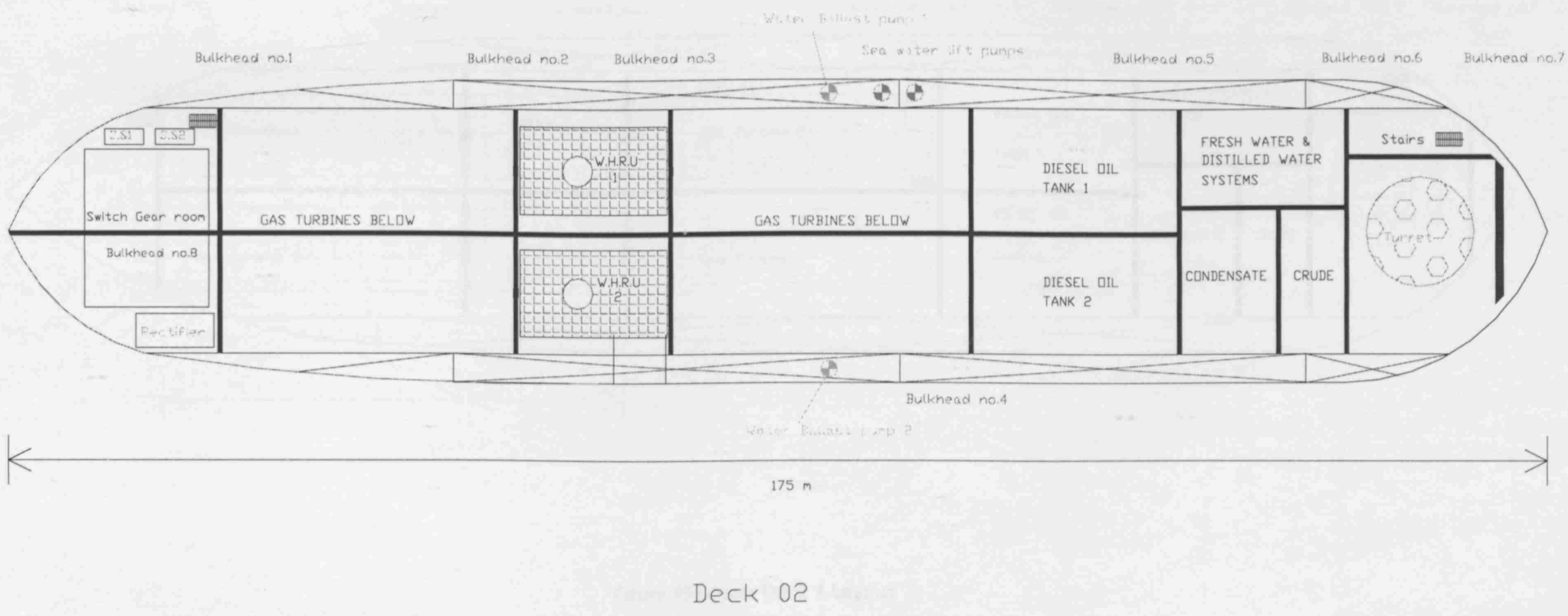


Figure 48 Lower Deck 2 Layout

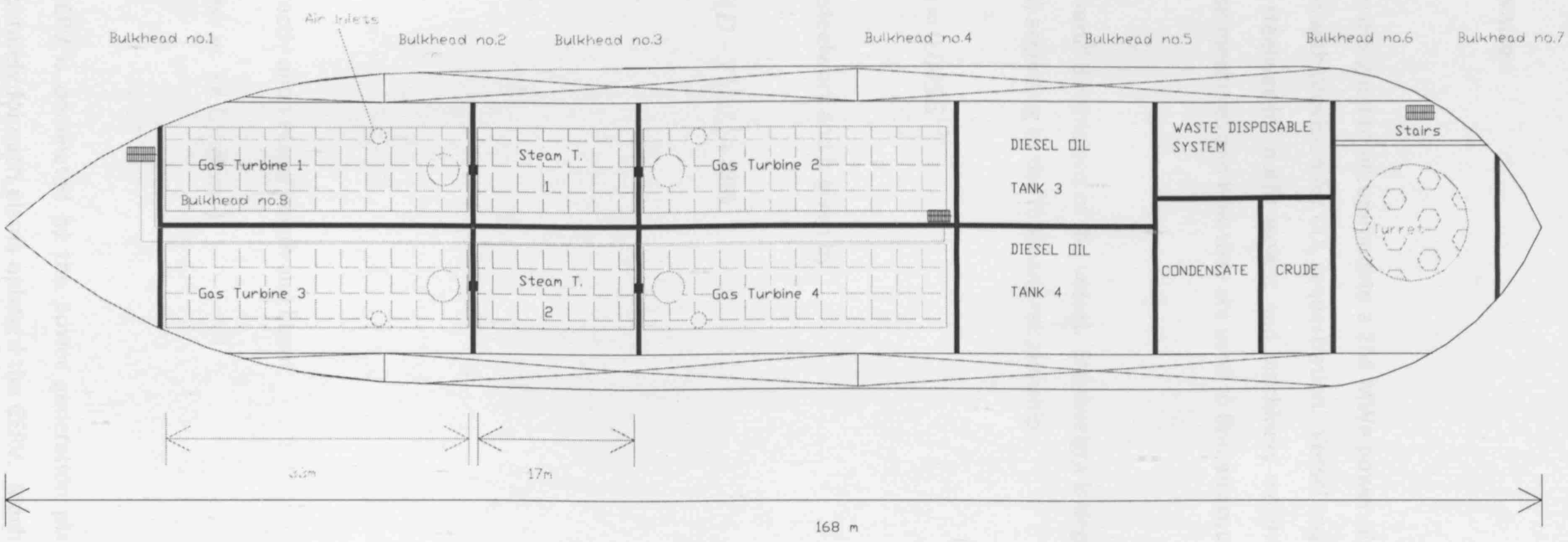


Figure 49 Lower Deck 3 Layout

5.5 Costing

5.5.1 CEPV Cost Derivation

Basic Vessel

The basic vessel has been designed to accommodate a 264 MWe power plant using a Rolls-Royce Trent[137] CCGT plant with provision for CO_2 sequestration. Vessel acquisition costs can be based in general on steelweight, outfit weight and machinery weight. The following subsections describe these measures and how they are used to find an acquisition cost[138].

Steelweight

This is calculated using overall dimensions of the vessel. Steelweight is dependent upon the 'E numeral' E (equipment) according to the following relationship.

Steelweight $Ws(tonnes) = 0.045E^{1.36}$ (5.1)

E is a measure of area of steelwork and is given by

$$E(m^2) = \{[B + T + 0.85(D - T)]xL\} + 800 \quad (5.2)$$

where

B = Beam (m)

T = Draught (m)

D = Depth (m)

L = Length. (m)

Outfit Weight

Outfit weight is based directly upon vessel length and beam:

$$Wo(tonnes) = 0.4(tonnes/m^2) \times L \times B(m^2) \quad (5.3)$$

Machinery weight

The machinery in the CEPV is dominated by the power generation plant and this cost element is dealt with separately for each plants onboard the CEPV. Machinery included at this point comprises gas processing plant and optional dynamic positioning system (DPS) thrusters and their control system, giving machinery cost Cm.

£6M has been included for gas processing plant and £10M for DP System control.

Vessel Cost

Vessel cost is derived from the preceding quantities using the expression138

Cv (£) $= (Cs + Co) + Cm$ (5.4)

where

Cs = Total cost of steel (£)

Co = Total cost of outfit (£)

Cm = Total cost of machinery (£)

The costs in brackets are multiplied by a factor of 1.6 if CO_2 sequestration is included. Steel cost Cs is not constant but is dependent upon Ws according to the following expression138.

Cs (£/tonne) $= 733 + 1700/\left(1 + (Ws - 1000)^{0.000235}\right)$ (5.5)

Variations of the Basic Vessel

Power Level

As a result of changes in the power generation level, some or all of the ship dimensions L, B, T, D change according to match the new electricity generating plant selected and a gas processing and CO_2 sequestration plant. Costs are calculated as set out above with the new dimensions. Changes to dimensions are set out in Table 24 for the various options considered.

Other Combined Cycle Gas Turbines

For power output levels other than 264 MWe with multiple generator sets (4 GTs or more), the vessel length L is scaled to reflect the change in power level. Other dimensions remain as for the 264 MWe vessel.

Large Gas Turbines

Where one generator set alone is employed, using one or two very large industrial gas turbines, all vessel dimensions increase accordingly.

Simple and Complex Cycles

For a simple cycle system with output 250 MW, vessel length is decreased significantly. Advanced cycle systems such as STIG or HAT systems involve a ship length that lies between a simple cycle vessel and combined cycle vessel lengths to accommodate steam generating equipment. Beam is driven by machinery and stability needs of the vessel.

CO_2 Sequestration

If sequestration plant is included all vessel costs are increased by a factor of 60%. This increase is based upon Amine Scrubbing equipment and is taken from a 392 MW plant example[41].

Table 24 CEPV Dimensions

Plant	GTs	STs	L(m)	B(m)	T(m)	D(m)
264 MW / 250.8 MW CC	4	4 or 2	185 (=L1)	35 (=L2)	12.8 (=L3)	19 (=L4)
176.8 MW CC	4	4	160	L2	L3	L4
279 MW CC	8	4	L1	L2	L3	L4
328 MW CC	4	4	205	L2	L3	L4
400 MW CC	4	4	225	L2	L3	L4
502 MW CC	8	8	250	L2	L3	L4
267 MW CC	2	1	190	40	14	21
263 MW CC	1	1	190	48	14.8	35
258 MW Simple Cycle	6	0	150	L2	L3	L4
259.5 STIG	6	0	170	L2	L3	L4
258 HAT	6	0	170	L2	L3	L4

5.6 Summary

This chapter has been concerned with an initial concept design of a Base Case CEPV. This has been achieved by a volume-driven vessel design methodology by first identifying the vessel type and machinery required e.g. gas processing plant, electricity generating plant and electrical equipment.

Although three suitable vessels were identified an FPSO was chosen because it is seen as a cheap solution to explore small or marginal gas fields in harsh weather conditions. An FPSO also has an added advantage over other options because of its flexibility to relocate to other gas fields.

The CEPV has been designed such that the layout will accommodate all onboard facilities, machinery space and accommodation. Safety of the crew and onboard machinery is considered as primary concern when designing the CEPV.

Final layout of the Base Case CEPV was decided upon consideration of providing a safe working environment in the machinery space, comfort of crew members, vessel stability, as well as allocations for storage fluid i.e. water, condensates, fuel. The total cost of the Base Case CEPV has been calculated by considering the construction of the basic vessel, and the purchase and installation of various plants and machinery.

6 Development of an Economic Model for the Base Case CEPV

6.1 Introduction

In this chapter, the design and development of a computer based Economic Model for the Clean Energy Producing Vessel (CEPV) is presented together with the results from an economic evaluation of a Base Case CEPV scenario.

The Economic Model has been built within Microsoft Excel and has been designed so it presents comparatively to standard economic models developed and used by oil and gas operators when evaluating the profitability of exploiting offshore gas reserves by pipeline. The Economic Model is a Discounted Cash Flow (DCF) model based upon Net Present Values (NPV) and it primarily establishes Capital Expenditure (CAPEX), Operational Expenditure (OPEX), Internal Rate of Return (IRR), and the Payback Period (PP) achievable for a specified CEPV design and gas field scenario (or scenarios). The IRR is a capital budgeting metric and a useful performance indicator of the efficiency of an initial investment whilst the PP is the time taken for the initial investment to be completely repaid to the investor.

This Chapter is therefore concerned with the following important aspects relating to the technical and economic evaluation of the CEPV:

- Justification of a 'Base Case' scenario including the CEPV design specifications and the gas field characteristics.
- Design and development of an Economic Model within Microsoft Excel using the DCF method.
- Using the Economic Model to analyse the defined Base Case scenario and presenting the results in a useful way that allows an investor to compare a Gas to Wire solution against a Gas to Pipeline solution for a specific gas field.
- Verification and validation of the Economic Model to ensure its robustness.

6.2 Base Case CEPV

In order to develop an Economic Model, a suitable Base Case CEPV needs to be technically defined and justified considering both costs and risks. The Base Case CEPV can then be evaluated economically so as to give a base-line CAPEX, OPEX, IRR and PP. The effects of changes to the technical specification of the Base Case CEPV can then be evaluated as can variations to the gas field characteristics and economic data. The economic performance of a CEPV variant can then be compared to the Base Case CEPV by considering the new values of CAPEX, OPEX, IRR and PP obtained.

6.3 Technical Specification of the Base Case CEPV

6.3.1 Electricity Generating Plant

The options considered for converting natural gas into electricity included fuel cells, diesel engines, steam plant and gas turbines as discussed in Chapter Three. The study, described in Chapter Three, suggested the optimum power generation plant would be a combined cycle gas turbine (CCGT) plant. This conclusion was based upon the knowledge that the CCGT plant is a low risk modern technology that is currently in use in shore-based power stations and also that it is 'marinised' as a propulsion plant for large ships[50]. The CCGT plant used in the Base Case CEPV consists of four Rolls-Royce Trent 21 Combined Cycle (each gas turbine generator is rated at 51.9 MWe) and two Rolls-Royce Steam Turbines (each rated at 28.2MWe each) thereby giving a maximum output power of 264 MWe. This arrangement optimises the number of prime-movers when considering weight, space, power output, cost and efficiency with the cost of the CCGT Plant being £71M.

6.3.2 Onboard Gas Processing

The onboard gas processing plant fitted to the vessel is provided to condition the raw gas received from the well prior to it being fed to the CCGT plant. The gas processing plant is primarily concerned with ensuring that the natural gas is of an appropriate quality and is at the right condition e.g. temperature, pressure and moisture level, for feeding to the gas turbines' combustors. The gas processing has a number of stages that includes amine scrubbing, dehydration, condensing, extracting and stabilising high value condensate products (which are then stored onboard prior to their periodic export via a shuttle tanker), gas compression and buffering. The optimum size of the gas processing plant is driven by the size of the electricity generating plant (the demand side) and the quality of the gas in the gas field (supply side). For the Base Case CEPV it was considered necessary that the plant should have a processing capacity of 41 mmscf/d of natural gas this being of sufficient size to maintain a steady flow to the CCGT plant for a range of gas fields. The risks associated with the processing plant design, manufacture, installation and operation is considered low simply because similar processing plants are in use in oil and gas production platforms at sea all over the world. The cost of this plant has been established at £6 M.

6.3.3 Transmission of the Generated Electrical Power

The options considered in Chapter Four for the transmission of the electrical power from the CEPV to a shore landing station were HVAC and HVDC. For HVDC transmission the system options included converters and inverters at each end of a monopolar single-core cable using sea return, a bipolar Integrated Conductor Return (ICR) cable or a bipolar Møllerhøj cable. The options considered for HVAC transmission included a three-core cable and three single-core cables in a flat arrangement or trefoil arrangement. For the Base Case, a bipolar HVDC system employing a Møllerhøj cable rated at 200kV and 250MW was preferred as discussed in Chapter Four. The risk associated with developing this cable and the converter and inverter stations is considered low since cables of this type are already in use for long distance subsea transmission. The cost of the HVDC transmission cable and the converters and inverters has been established at £8 M.

6.3.4 CO_2 Sequestration Plant

The natural gas that is burnt in the CCGT plant will produce exhaust gases of which Nitrogen and CO_2 will be predominant, assuming low NO_x combustors are used. The CO_2 sequestration plant would be designed such that the CO_2 is split away from the other exhaust gases before being pumped into an empty oil or gas field i.e. a permanent storage site, using compressors. The Base Case CEPV uses a plant design based upon an existing CO_2 sequestration plant that uses MEA scrubbing and is sized from a 392 MW power plant example[41]. The technology is relatively new and it would appear that this is the first time it has been considered for shipboard use hence the solution proposed for the CEPV's CO_2 sequestration must be considered as being high risk. The costs are a 60 % of the generating plant cost, justified by discussing the design with a major oil and gas company[139].

6.3.5 Vessel Design

The vessels considered for the CEPV were the tension-leg platform, semi-submersible, and FPSO as discussed in Chapter Five. Each vessel has advantages and disadvantages and none provides the perfect platform for all of the gas field scenarios. For the Base Case CEPV, an FPSO was selected as it presented a compromise between risk, cost, volume, stability, sea-keeping, and capability. The FPSO offers deep water capability and is capable of operating in high sea states and has a large internal volume. The CEPV represents a completely new design so the risks in its development cannot be considered as being low but on the other hand, construction of large mono-hull vessels of similar type is well understood by shipyards, so neither can it be considered as being high risk i.e. the CEPV design and build is considered medium risk. The cost of the CEPV is estimated at £66 M from a study of FPSO vessels.

6.3.6 Submerged Turret Production and Transmission Cable Connection

Two items of technology are considered as being high risk namely the submerged turret production (STP) and the riser cable system.

The STP must accommodate both the gas riser from the well on the seabed, the CO_2 down pipe to the storage site and a cable riser for export of electricity. Such a turret would be a special item that would need to be designed, manufactured and tested to ensure its safe use throughout the working lifetime of the CEPV. The cost of this high risk item is estimated to be £7 M, this cost being justified on the basis that existing STPs cost in the region of £4 M thereby allowing a substantial margin for its development.

The riser cable connects the transmission line on the seabed to the vessel to allow electricity to be exported. The riser cable will be designed such that it is lightweight and so flexible to allow it to flex with vessel movement i.e. through the action of tides and waves. The riser cable will be 'mechanically dynamic', designed specifically for this application and would need to be designed, manufactured and tested to ensure continued use throughout the working lifetime of the CEPV. The cost of this cable is estimated to be £57M, this cost being justified by examining existing cable costs and allowing a substantial margin for its development.

6.3.7 Base Case Gas Field Specification

In addition to the technical design specification for the Base Case CEPV, a gas field, which is to be exploited in the lifetime of the CEPV, needs to be specified. As discussed in Chapter Two, there are currently a greater number of gas field discoveries relative to oil field discoveries in the North Sea. Large unexploited gas fields exist offshore in deep water and there is also an abundance of exhausted offshore oil fields in which significant quantities of natural gas still remain[13]. There are therefore a number of different types of natural gas reserves that the CEPV could exploit. Some of the gas fields will require drilling and capping by hiring a drilling rig i.e. for the gas reserve to be made ready for the CEPV. Other gas fields for which the CEPV could be used are ones previously exploited for their oil but now lie abandoned with significant quantities of natural gas. For these fields, the wells will already be capped negating the need for a drilling rig. Other fields that may be exploited by the CEPV are oil fields currently in production, which contain a high proportion of natural gas which is currently being re-injected into the well to meet the strict regulations on flaring.

Gas reserves of most interest to the CEPV will be those capped reserves which possess a natural pressure which will be used to propel the gas to the surface (known as primary recovery) thereby eliminating drilling and extraction costs. Abandoned natural gas in an area where a license to exploit has already been paid for then it is appropriate to consider the gas as being 'free'.

For the Base Case CEPV a previously capped single reserve containing 8 bnm^3 of natural gas having a quality of 38 MJ/m^3 located 150 km from the shore in a water depth of 90 m was selected. This scenario is justified because a field of this type is known to exist and it is in close proximity to a previously exploited oil field which has the potential to be used for CO_2 storage[139]. However, for the purpose of the Base Case CEPV it has been assumed that CO_2 sequestration is not used so as to allow cost comparisons with onshore electricity generation.

6.4 The Economic Model

6.4.1 Overview

An Economic Model was constructed in Microsoft Excel to establish the economic viability of the CEPV concept for a range of operating scenarios. The Economic Model has been constructed in six sub-blocks as represented in Figure 6.1. The Economic Model for the CEPV has been designed and built so it presents comparatively to other models designed for economic evaluation of oil and gas field exploitation by pipeline[139]. Developing the CEPV Economic Model allows an operator to compare and contrast various options for exploiting a new gas field e.g. a gas reserve could be exploited using gas-to-pipe; gas-to-tanker; and gas-to-wire.

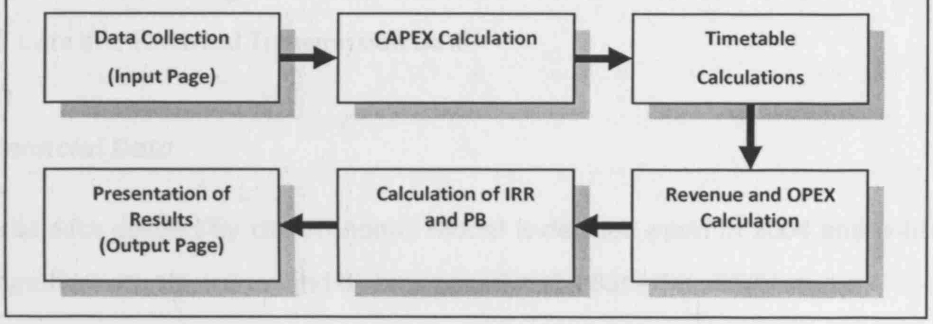


Figure 50 The Economic Model in Block Form

The CEPV Economic Model consists of three-pages written in the Microsoft Excel spreadsheet which covers all the blocks shown in Figure 6.1. Page One of the model is the Input Page where data associated with the CEPV design, the gas field and the key external economic parameters are inputted. Page Two is the calculation page where CAPEX, OPEX, IRR, PP and other financial data are calculated. Page Three is the output page where the results of the study are presented in tabular and graphical form giving the performance indicators.

The Economic Model is designed as a Discounting Cash Flow (DCF) model. By discounting future quantities of money to an equivalent Present Value (PV) allows accurate comparison of costs and revenues through the working life of the project. Revenues are thereby correctly apportioned to cover both debt repayments and interest outstanding at the end of each accounting period. The discount rate is used to find a project's Net Present Value (NPV) and the project's Internal Rate of Return (IRR). The latter quantity is the rate that will yield a zero NPV so it may be compared with the cost of capital.

The Economic Model is based upon accounting periods of one year, with the project beginning at the start of a full accounting period. The philosophy behind this approach is to value the CEPV project using the concept of 'value of money' with all future cash flows being discounted to give them a Present Value. The discount rate used is the appropriate cost of capital and incorporates judgement as to uncertainty and risk of future cash flows.

6.4.2 Input Page

Four sets of input data are required to set up a specific scenario in which the CEPV will be used to exploit an offshore gas reserve. These data sets are Financial Data, CEPV Technical Data, Field Data and Electrical Transmission Data.

Financial Data

The financial data needed by the Economic Model is decided upon in 2004 and is listed in Table 25together with the values and its range used in the Base Case CEPV study.

Table 25 Input Data Table: Financial Data Section

Items	Value	Range
Inflation Rate %	2	1 – 10
Interest Rate %	5	1, 2 & 3% above Inflation Rate
Gearing (MAX 100%)	25	0 – 100
Corporation Tax %	30	12.5 – 40
Carbon Tax \$/tonne CO_2	0	0
Length of project (yrs, MAX 25)	15	15
Electricity Av. Revenue £/MWh	38	20 – 100
Condensate Sale Price (\$/bbl)	90	20 – 200
Exchange Rate £1=	\$1.50	1.00 – 3.00
Discount Rate (for NPV output)	5	5

The *Inflation Rate* is a measure of the rate of increase of a price index and this is assumed to be constant throughout the project life. The Economic Model is a 'real term' model and any historical cost elements or depreciation is adjusted using the inflation rate. The Base Case inflation rate is set at 2% which reflects the average annual Consumer Price Index (CPI) in the UK over the past five years and is also the Bank of England target rate[140].

The *Interest Rate* is the annual rate paid on debt capital. The Economic Model uses the interest rate to make appropriate allowances against revenue for tax purposes and it is assumed constant throughout the working life of the CEPV. The money borrowed is considered to be subject to interest at a constant rather than variable rate. The Base Case rate is set at 5 % because UK interest rates have fluctuated between 3.75 % and 5.75 % from 2003 to 2007[141].

Gearing represents the ratio of debt capital to shareholders' equity in the capital employed in the CEPV project. In the Economic Model, gearing ratio is important because debt interest on money borrowed is allowable against income for tax purposes whilst equity is not subject to the same privilege. The Base Case gearing ratio is set at 25 %, this being representative of how companies are likely to operate the CEPV and that a high gearing ratio is considered risky[142].

Corporation tax is the tax levied by HM Revenue and Customs (HMRC) on the taxable income or profits made by the CEPV operator. The main rate of corporation tax is 30 % against which allowances can be made for CAPEX and interest payments. The Economic Model deducts allowances from profits before applying corporation tax with 100 % capital allowances on CAPEX. The Base Case rate has been set at 30 %. In practice, a CEPV may attract a higher rate since, from April 2002, North Sea profits from oil and gas have attracted a supplementary corporation tax rate of 10 %, which was subsequently increased to 20 % from 1 January 2006, making the main rate 50 %[143]. However, it is not clear whether these additional taxes would apply to the CEPV simply because the gas is not landed. HMRC is not able to confirm the tax situation at this time.

The operators of the CEPV could also consider registering the CEPV using Open Registry, or commonly called Flag of Convenience, to avoid hefty corporation tax. Although this is an attractive option but revenues from the UK's North Sea is subject to British Law and therefore deeper understanding of the relevant legislation is required. In this thesis, Open Registry is not considered for the CEPV.

Carbon tax is defined as a tax per tonne of CO_2 exhausted into the atmosphere. For every tonne of natural gas burnt, 2.77 tonnes of CO_2 are exhausted. The current mechanism for regulating CO_2 emissions is Europe's Emissions Trading Scheme which has been the subject of some mixed fortunes[144]. For the Economic Model the implementation of Europe's Emissions Trading Scheme was considered to be too complex so the solution adopted to account for CO_2 emissions was to assume a tax levied per tonne of CO_2 exhausted. For the Base Case, the Carbon Tax rate is set to zero simply because there is presently no financial incentive to employ CO_2 sequestration.

Length of project represents the time the CEPV is in operation on a given project. For the Base Case the Length of Project was set to 15 years.

Electricity Average Revenue is the average income the project receives from the sale of generated electricity. The income is determined by the electricity trading scheme, e.g. British Electricity Trading and Transmission Arrangements (BETTA) or alternatively by a private arrangement with a dedicated customer e.g. a large industrial complex such as a refinery or chemical works. The Base Case price is set at £38/MWhr, this being average price paid in 2007[145].

Condensate Sale Price is the price obtained when selling valuable condensate products obtained during the processing of natural gas onboard the CEPV. The Economic Model considers condensates as being an additional revenue source. The costs associated with transporting the condensate from the CEPV to shore, using a shuttle tanker, is considered the financial concern of the condensate purchaser rather than the operator of the CEPV hence they are excluded from the Economic Model. The Base Case sale price is set at $90/bbl this being justified by the average spot market price less transport costs[146].

Exchange Rate is the US Dollars/UK Pound Stirling exchange rate. This rate is needed by the Economic Model because oil and gas is priced in US Dollars e.g. the Condensate Sale Price is set in US dollars. The Base Case uses a rate of $1.50 to £1 as this is the near average rate over the past 10 years[147]. The exchange rate in 2008 is $1.78 to £1[148].

Discount Rate sets the level of discounting in order to convert future income and expenditure to NPV. The Discount Rate used by the Economic Model is considered to be constant throughout the project period. The Base Case rate is set to 5 %, which is an appropriate rate for oil and gas projects[139].

Plant Data

The CEPV technical data needed by the Economic Model is listed in Table 26 together with the values used in the Base Case CEPV study.

The options for the CEPV Generating Plant are detailed in a separate Generator Set Options sheet in the Economic Model and each is given an identification number. The options available are the realistic options which have been identified from the research work undertaken in Chapter Three. The Base Case generating plant is a Rolls Royce Trent CCGT rated at 264 MW plant (Option 5) discussed earlier in this Chapter.

Table 26 Input Data Table: Plant Data Section

Generating Plant	5
DP installed 1 = Yes ; 0 = No	1
DP used to keep station 1 = Yes ; 0 = No	1
Maintenance Estimates: (1) – days planned/yr	6
(2) - days unplanned/yr	6
Gas Processing Plant + Vessel Services (% generated power)	5
CO_2 Sequestration 1 = Yes ; 0 = No	0
Ship time to refit (yrs)	15

Dynamic Positioning (DP) system may or may not be installed and, if installed, it may or may not be used to keep station since permanent anchoring may be considered as an alternative solution. The Economic Model considers whether a DP is installed (CAPEX) and whether it is operated (OPEX). The Base Case assumes a DP system is fitted on the CEPV and it is used to keep position.

Maintenance Estimates are required to establish lost production days due to a complete shutdown of electricity generating operations through planned and unplanned maintenance. The Economic Model uses the Maintenance Estimates to adjust income and where days of unplanned maintenance occur, an additional cost of purchasing electricity from other electricity generators to fulfill contractual obligations is included. For the Base Case it is assumed that six days are needed for planned maintenance and six days for unplanned maintenance. This has been calculated using data from existing CCGT plant and by considering operation in the marine environment[139].

Gas Processing Plant and Vessel Services is the percentage of generated electricity used onboard the CEPV for processing natural gas and providing onboard services. The Economic Model considers this percentage of electricity generated as being lost revenue. The Base Case value is set to 5 % as this represents approximately 13 MW, which is realistic when considering the CEPV electrical loads. Slight variations are likely due to both the quantity and quality of the natural gas extracted.

CO_2 Sequestration is one of the unique features of the CEPV. However, it may not be possible or economically desirable to use it depending upon the CEPV location and financial incentives. In the Economic Model the CO_2 sequestration feature can be turned on and off to reflect different operational scenarios. If CO_2 sequestration is used then electrical power will be required to power the CO_2 sequestration plant e.g. compressors, which means a reduced amount of electricity available for export hence a reduced revenue stream.

Ship Time to Refit indicates the operational life of the vessel before it needs a major refit in a dry dock where it will be out of operation. For the Base Case, 15 years is used since this represents the requirements of the major classification societies for most ships.

Field Data

Table 27 Input Data Table: Field Data Section

Distance to shore (km)	150
Field size (bn m^3)	8
Wells (production)	2
Wells (status) 0 = abandoned 1 = exploration	1
Relocation time (yrs)	0.5
Gas price (£/MMSCF)	0
Gas quality MJ/m^3	38
Condensate ratio bbl/mmscf	40
Water depth (m)	90

The CEPV field data needed by the Economic Model is listed in Table 27 together with the values used in the Base Case CEPV study.

Distance to Shore is the location of the vessel from the shore landing station. In the Economic Model the Distance to Shore influences the type of electrical transmission method that will be used i.e. AC or DC, and the length of the cable needed (CAPEX) and the transmission losses incurred (OPEX). The Base Case value is 150 km this being selected based upon a gas field to the west of Shetland Islands in the North Sea[149].

Field Size is the size of the gas field measured in bnm^3. The Economic Model uses this information to establish the amount of gas that is recoverable. The Base Case value is 8 bn m^3 this being selected based upon a gas field to the west of Shetland Islands in the North Sea[139].

Wells (Production) is the number of wells used throughout the CEPV operations at a specific field whilst Wells (Status) indicates whether the wells have been abandoned e.g. from earlier exploration, or are newly drilled specifically for the CEPV. In the Economic Model the installation of newly drilled wells affects the drilling and subsea installation costs (CAPEX) whilst the number of wells affects the gas flow characteristics over the project period (OPEX and Revenue). The Base Case value is '2' new wells this being representative based upon a gas field to the west of Shetland Islands in the North Sea[149].

Relocation Time is the interruption in operations expected when moving the CEPV from one gas field to another. Relocation involves retrieval of the electrical transmission cable and relaying it to the next gas field to be exploited as well as moving the CEPV. In the Economic Model Relocation Time is a period of which there will be no revenue but considerable costs (OPEX). The Base Case value is six months (0.5 year) this accounting for initial setup of the CEPV at the site of the gas field.

Gas Price is defined as the price of the gas drawn from the well. The Economic Model uses Gas Price to calculate Revenue. The Base Case considers the gas free since it is taken from an untapped stranded natural gas field where wells have been previously installed and capped from earlier exploration. The gas is assumed to rise under its own pressure.

Gas Quality in MJ/m^3 is used in the Economic Model to calculate the rate of consumption by the CCGT plant thereby calculating the rate of depletion of the gas field. The Base Case value is 38 MJ/m^3 which reflects the quality of the gas from a gas field to the west of Shetland Islands in the North Sea[139].

Condensate Ratio is the proportion of condensate present in the raw natural gas when received onboard the CEPV. It is used by the Economic Model to calculate a revenue stream from the sale of condensate. The Base Case value is 40 bbl/mmscf, which reflects the characteristics of the gas from a gas field to the west of Shetland Islands in the North Sea[149].

Water Depth is used by the Economic Model to calculate length of the gas riser, CO_2 down pipe, and the cable riser (CAPEX). The Base Case value is 90 m this being the depth of the water a gas field to the west of Shetland Islands in the North Sea[149].

Electrical Transmission System

The Electrical Transmission data needed by the Economic Model is listed in Table 28 together with the values used in the Base Case CEPV study.

In the Economic Model, information on the Electrical Transmission System is needed to calculate CAPEX and transmission losses (OPEX) when exporting electrical power from the CEPV to a shore-based landing station. The electricity may be exported using either AC (for near shore scenarios) or DC (for far shore scenarios) and different cable types are available for selection. For the Base Case, DC transmission is used and an ICR cable rated 200 kV is selected. For the Base Case it is assumed that connection is to the National Grid hence the Economic Model calculates costs payable to the National Grid (OPEX)[150].

Table 28 Input Data Table: Transmission Data Section

Transmission Type AC/DC	DC
Grid Connection 1/0	1
AC OPTIONS	
Cable Formation Flat/Trefoil	Trefoil
DC OPTIONS	
Single core sea return 1	
Metallic return 2	3
ICR 3	
Voltage 200 250 300 350 400 kV	200
Conductor Material cu/al	Al
Insulation Material paper/XLPE	Paper

6.4.3 Calculation Page

The Calculation Page imports the data from the Input Page to determine values for CAPEX, Revenue, OPEX and Performance Indicators including NPV, IRR and PP.

CAPEX (Capital Expenditure)

In the Economic Model, CAPEX is calculated by summing the total cost of the items listed in Table 29.

Table 29 Items Included in CAPEX Calculation

CEPV	Vessel + Gas Processing Plant + CCGT Plant + Onboard CO_2 Sequestration Plant + Onboard Electrical System
Wells	Number of wells drilled and well head installed for gas supply and for CO_2 injection.
Risers	Installation of dynamic risers for gas supply and for CO_2 export from CEPV.
Cable	Subsea transmission cable manufacture and installation at site.
Onshore	Electrical equipment at the transmission cable receiving end.
Connections	National Grid connection charges.
Relocations	Cable recovery and relaying; further drilling and new riser purchase.
Final	Cable recovery at the end of CEPV operations.

The CEPV has a construction cost. This cost is calculated by summing the fabrication cost, materials cost, equipment cost and installation cost. The construction cost is then derived by allowing a percentage increase to cover EPCS (engineering, procurement, construction and supervision), operator costs (engineering costs incurred by others) and insurance. A total cost for each system is then obtained by adding a contingency cost to the construction cost by a further percentage increase.

Revenue

Electricity revenues are calculated using an annual mean sale price which is calculated using BETTA. The annual revenues account for the number of generator sets operated, their efficiency and losses in generation and transmission. Condensate revenues are calculated using the inputted Condensate Sale Price which should be based upon the annual mean oil price and is dependent upon the quantity and quality of the condensate produced.

OPEX (Operational Expenditure)

In the Economic Model, OPEX is calculated by summing the items listed in Table 30 on an annual basis.

In calculating OPEX the following specific issues being allowed for:

- Some costs are incurred all the time irrespective of whether the plant is operating or not or whether the CEPV is on station or in transit. Examples of such costs include manning costs.
- Some costs are incurred at specific points in time for example subsequent drilling costs and cable re-laying costs.
- Taxation Allowances consist of depreciation, OPEX and interest payments. Assets are assumed to have zero residual value at the end of the project so depreciation is calculated on a straight-line basis. As the model operates in real terms, all other entities are assumed to be subjected to inflation. Depreciation allowances are discounted to account for the fact that they are, in money terms, based upon the historical cost of procurement.
- Final Costs include decommissioning the plant and the recovery of the cable at the end of the project therefore they are subject to the maximum discount factor.

Table 30 Items Included in OPEX Calculation

Manning	Crew wages and benefits. Crew support e.g. provisioning and crew exchange.
CEPV Maintenance	Generator running costs based on ABB maintenance schedule. CO_2 sequestration running costs based upon BP data from an MEA Scrubbing Plant. Gas processing plant based upon a maintenance schedule currently used onboard offshore oil rigs. Vessel maintenance based upon Lloyds Register rules.
Cable	A flat rate is applied (£/km/year) as representing cost of cable maintenance which includes repairing cable breaks.
Connections	For connection to the National Grid, connection, transmission and balancing service charges are calculated based upon guidelines from the National Grid150.
Recovery	Cable recovery cost at the end of CEPV operations.

Performance Indicators

The Performance Indicators calculated in the Economic Model are the Internal Rate of Return (IRR), Net Present Values (NPV), and Payback Period (PP).

Net Present Values

In the Economic Model the Net Present Values are calculated by using an annual Discounted Cash Flow (DCF) model. Future quantities of money are discounted to an equivalent present value to enable comparisons to be made of revenues generated and costs incurred throughout the life of the project. Income is apportioned to cover both debt repayment and interest outstanding at the end of each accounting period. Each cash inflow and outflow is discounted such that

$$NPV = C_0 + \sum_{t=1}^{N} \frac{C_t}{(1+r)^t} \qquad (6.1)$$

Where

t = cash flow (£)

N = total time (year)

r = discount rate (pu)

C_t = net cash flow (£)

C_0 = initial investment (£)

Internal Rate of Return

In the Economic Model the Internal Rate of Return is calculated to find the value of the discount rate which gives an NPV of zero to allow a comparison to be made with the cost of capital. This can be expressed as:

$$NPV = C_0 + \sum_{t=1}^{N} \frac{C_t}{(1+r)^t} = 0 \qquad (6.2)$$

Payback Period

In the Economic Model the Payback Period is calculated by dividing the CAPEX by the Cash Flows calculated using the DCF model. In other words, this is simply the time taken for discounted net revenues to match the initial expenditure. In the Economic Model annual discounted net revenues are summed until it matches the initial expenditure, giving the payback period quoted in years.

6.4.4 Output Page

The output page consists of three parts namely the Summary, the Economic Analysis, and the Costs.

Summary

The summary provides an outline of the scenario as defined at the Input Page and additionally lists the results from the Calculation Page namely CAPEX, OPEX, Revenue, IRR, NPV and PP. The summary page provides only key data and does not provide the detail necessary for economic interrogation.

Economic Analysis

The Economic Analysis is the main output of the Economic Model. This allows detailed economic interrogation across the lifetime of the project. The information is presented in detail and is divided into the following areas:

- Financial Summary which presents the CAPEX, OPEX, NPV and IRR post tax for the project.
- Plant Performance which presents the maximum power generated, maximum power transmission, the electricity sale price and the optimum overall efficiency for each locations of the CEPV.
- Plant Production Profiles (Gas Consumption) which shows gas consumption from the gas field(s) and is plotted across the project period.
- Capital Costs which presents the initial CAPEX and costs for subsequent relocations of the CEPV.
- Operating Costs which presents OPEX for the first year which is subsequently used to calculate OPEX for the remaining project period.
- Economic Analysis showing the following:
    - Net Present Values
    - Pre-Tax and Post-Tax IRR
    - The Payback Period
- Cash Flow on an annual basis and Cumulative Net Cash Flow both actual and discounted
- Revenue Distribution in a pie chart showing CAPEX, OPEX, tax and net cash flows.

Costs

Costs give a breakdown of expenditure associated with the CEPV scenario i.e. CAPEX and OPEX. Materials and Equipment costs, fabrication and installation costs, EPCS, Operator and Insurance costs and Contingency costs are all presented here. The percentages used for EPCS, Operator, Insurance and Contingency costs can be changed as required.

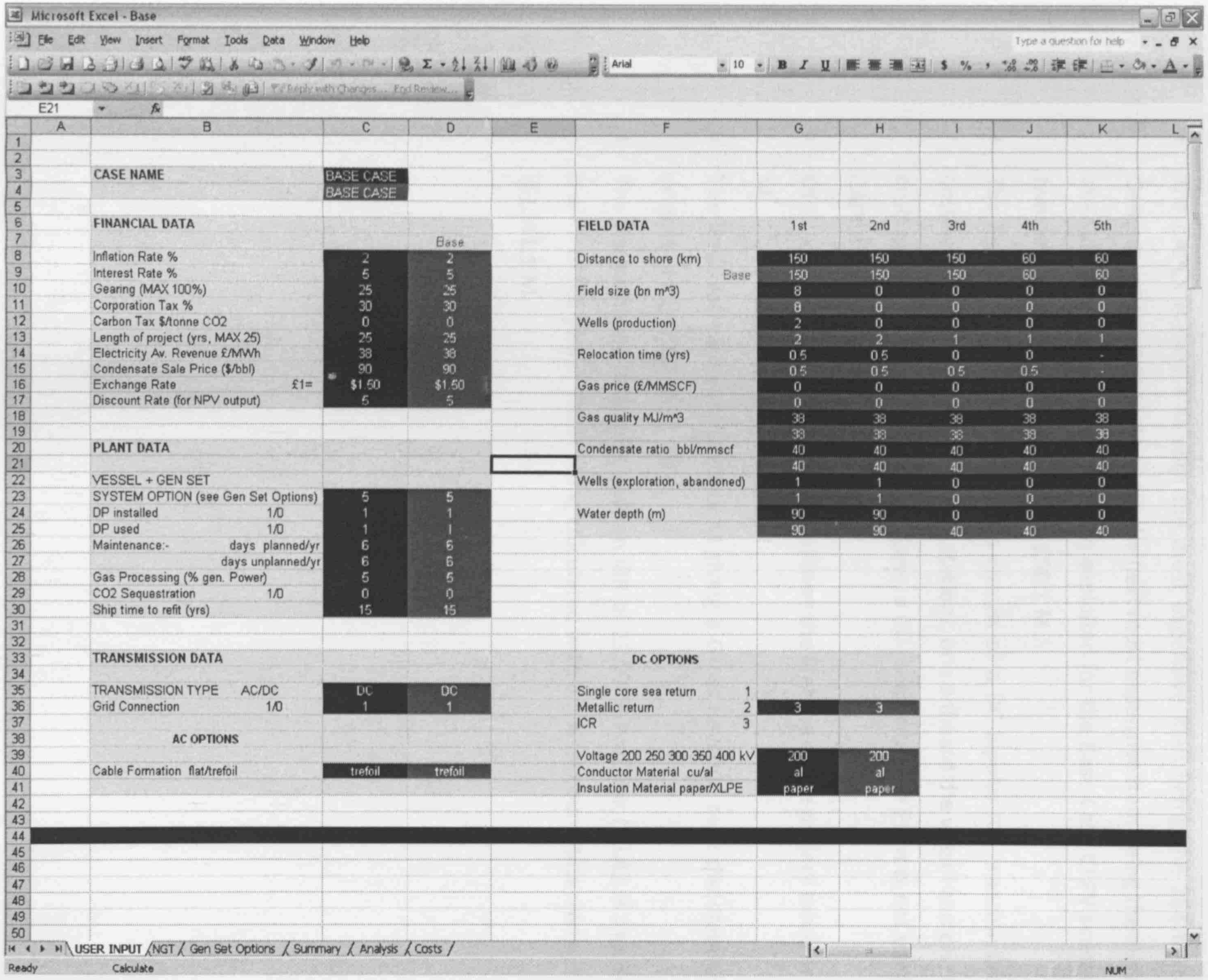
6.5 The Economic Evaluation of the Base Case

The Base Case CEPV and gas field scenario described in this chapter was evaluated using the Economic Model.

6.5.1 Input Page

The Input Page of the Economic Model uses the financial data and technical specifications defined in the Base Case CEPV and gas field scenario and are shown in Figure 51.

There are two columns in Figure 51 because the Economic Model allows a comparison to be made between the Base Case and another scenario at the same time.



Microsoft Excel - Base

	B	C	D
3	CASE NAME	BASE CASE	
4		BASE CASE	
6	FINANCIAL DATA		
7			Base
8	Inflation Rate %	2	2
9	Interest Rate %	5	5
10	Gearing (MAX 100%)	25	25
11	Corporation Tax %	30	30
12	Carbon Tax $/tonne CO2	0	0
13	Length of project (yrs, MAX 25)	25	25
14	Electricity Av. Revenue £/MWh	38	38
15	Condensate Sale Price ($/bbl)	90	90
16	Exchange Rate £1=	$1.50	$1.50
17	Discount Rate (for NPV output)	5	5
20	PLANT DATA		
22	VESSEL + GEN SET		
23	SYSTEM OPTION (see Gen Set Options)	5	5
24	DP installed 1/0	1	1
25	DP used 1/0	1	1
26	Maintenance:- days planned/yr	6	6
27	days unplanned/yr	6	6
28	Gas Processing (% gen. Power)	5	5
29	CO2 Sequestration 1/0	0	0
30	Ship time to refit (yrs)	15	15
33	TRANSMISSION DATA		
35	TRANSMISSION TYPE AC/DC	DC	DC
36	Grid Connection 1/0	1	1
38	AC OPTIONS		
40	Cable Formation flat/trefoil	trefoil	trefoil

	F	G	H	I	J	K
6	FIELD DATA	1st	2nd	3rd	4th	5th
8	Distance to shore (km)	150	150	150	60	60
9	Base	150	150	150	60	60
10	Field size (bn m^3)	8	0	0	0	0
11		8	0	0	0	0
12	Wells (production)	2	0	0	0	0
13		2	2	1	1	1
14	Relocation time (yrs)	0.5	0.5	0	0	-
15		0.5	0.5	0.5	0.5	-
16	Gas price (£/MMSCF)	0	0	0	0	0
17		0	0	0	0	0
18	Gas quality MJ/m^3	38	38	38	38	38
19		38	38	38	38	38
20	Condensate ratio bbl/mmscf	40	40	40	40	40
21		40	40	40	40	40
22	Wells (exploration, abandoned)	1	1	0	0	0
23		1	1	0	0	0
24	Water depth (m)	90	90	0	0	0
25		90	90	40	40	40
33	DC OPTIONS					
35	Single core sea return 1					
36	Metallic return 2	3	3			
37	ICR 3					
39	Voltage 200 250 300 350 400 kV	200	200			
40	Conductor Material cu/al	al	al			
41	Insulation Material paper/XLPE	paper	paper			

USER INPUT / NGT / Gen Set Options / Summary / Analysis / Costs

Figure 51 Input Page

6.5.2 Output Page

The Economic Summary on the Output Page for the Base Case CEPV is shown in Figure 6.3. From this the following observations can be made:

- The CAPEX is £437.4 M with the most expensive item being the 264 MWe CCGT Generator Sets at £153.7 M with the next most expensive item being the vessel itself at £66.3 M. A new gas field is being exploited for the Base Case CEPV scenario with two new wells being drilled costing £56.1 M.
- The Electrical Transmission System consist of a DC bipolar ICR transmission cable costing £57.5 M and two converter stations, one onboard the vessel and one ashore, costing £44.2 M each. In the Base Case, a CO_2 sequestration Plant is not used hence CAPEX for this item is zero.
- OPEX in the first year is £17.3 M and over the lifetime of the project totals at £258.4 M.
- The Revenue each year is £98.5 M giving a Gross Revenue over the lifetime of the project of £1,477.2 M.
- The Performance Indicators give an IRR of 13.97 % Post-Tax (19.42 % Pre-Tax) and the PP of 6.6 years. These being calculated with a 5 % Discount Rate where the NPV is £241.1 M.

		Gas-to-Wire	
CAPEX			
	Vessel		
	Basic Vessel	66.3	(all £M)
	Generator Set	153.7	
	Sequestration Plant	0.0	
	Electrical Equipment	44.2	
	Platform		
	Structure	-	
	Processing Plant	-	
	Wells and Subsea Installation	56.1	
	Risers (Dynamic)	2.8	
	Transmission Cables	57.5	
	Pipeline	-	
	Onshore Electrical Equipment	44.2	
	Connections	0.1	
	Miscellaneous	0.0	
	Relocations	0.0	
	Decommissioning	12.7	
	Total	437.4	£M
OPEX	First year	17.3	£M
	Total	258.4	£M
REVENUE	Revenue per year (max.)	98.5	£M
	Gross Revenue	1477.2	£M
IRR	Post Tax	13.97	%
	Pre Tax	19.42	%
NPV	NPV at 5%	241.1	£M
PAYBACK	Payback Period	6.6	years

Figure 52 Summary

The Economic Analysis for the Base Case is shown in Figure 52. This analysis provides greater detail on the Base Case CEPV scenario over the Economic Summary. The following additional observations can be made:

- The Base Case is a single site installation and natural gas is available at the required pressure across the lifetime of the project meaning the gas consumption profile is constant.

- The generating plant exports 229.8 MW of electrical power to give an overall efficiency of 43.5 % i.e. energy contained in the natural gas arriving onboard the CEPV to electrical energy into the National Grid.
- At a sale price of $90/bbl, the revenue from the sale of condensate will be £31.4 M per annum across the lifetime of the project as shown in Figure 6.5. This amount contributes approximately 31 % of the total revenue per annum.
- At the beginning of year one (end of year zero) the capital outlay (CAPEX) is £424.7 M before the CEPV brings in any revenue as shown in Figure 6.5. The annual gross revenue from year one is £ 98.4 M whilst OPEX is £17.2 M per annum giving a total Field Cash Flow in the first year of £81.2 M which decreases to £50.2 M in the year 15 using a 5 % Discount Rate.

The Cash Flow Model shown in Figure 53 gives the Present Values from which the Post-Tax IRR (13.97 %), Pre-Tax IRR (19.42 %) and PP (6.6 years) are calculated.

The Revenue Split is shown in Figure 54 for both actual (undiscounted) and discounted values. The PP for the actual values is just over five years whilst the PP using the discount rate is 6.6 years.

Considering the Revenue Distribution pie chart shown in Figure 55, then it is apparent that CAPEX takes up the largest proportion of revenue distribution. OPEX and Tax takes up 18 % each leaving a Net Cash Flow (Profit) of 23 %.

		CASE NAME :	BASE CASE						
					Electricity Sale Price			38	£/MWh
					Gas sale Price			20	p/therm
MOBILE POWER PLANT:- KEY FACTS					Condensate Sale Price			60	£/bbl
	Vessel :-		Monohull						
	Gen. Set :-		4 x Rolls-Royce Trent Combined Cycle, total 264 MW gross output						
	Sequestration :-		None						
	Transmission :-		DC; ICR (Aluminium, paper)						
	Shore :-		Grid connection						
Location			1	2	3	4	5		
	Recoverable Reserves								
	gas (bn m3)		8	-	-	-	-		
	liquids (mmbbl)		11.3	-	-	-	-		
	Distance Offshore (km)		150.0	-	-	-	-		
	Water Depth (m)		90	-	-	-	-		
	Timetable								
	Field Start (year)		0	-	-	-	-		
	Field End (year)		15.00	-	-	-	-		
	Wells								
	Production		2	-	-	-	-		
	Sequestration		0	-	-	-	-		
	Other		1	-	-	-	-		
Financial Summary									
	Capital Costs (2007 terms)				437.4	£M			
	Operating Costs 1st year (2007 terms)				17.3	£M			
	Present Value at		5%		241.1	£M			
	Rate of Return % (after tax)				13.97	%			
Plant Performance									
	Electricity								
	Location			1	2	3	4	5	
	Maximum Generation MW			264	-	-	-	-	
	Maximum Transmission MW			229.8	-	-	-	-	
	Maximum Sale MW			211.7	-	-	-	-	
	Optimum Overall Efficiency %			43.5%	-	-	-	-	

Figure 53 Economic Analysis (Page 1)

Capital Costs (2007 terms)										
		Location	Initial	2nd	3rd	4th	5th			
	Gen Set		153.7	-	-	-	-			
	Vessel		66.3	-	-	-	-			
	Sequestration Equipment		0.0	-	-	-	-			
	Cable		57.5	-	-	-	-			
	Electrical Equipment		88.4	-	-	-	-			
	Grid Connection Charges		0.062	-	-	-	-			
	Wells, Risers		58.8	-	-	-	-			
	Transit		-	-	-	-	-			
	Recovery (final)		12.7	-	-	-	-			
	TOTAL £M		437.4	-	-	-	-			
Operating Costs (2007 terms) 1st yr £M										
	Running		12.7							
	Corporation Tax		0.0							
	CO2 Tax		0.0							
	Insurance		2.3							
	Misc. and Admin		2.3							
	Total		17.3							
ECONOMIC ANALYSIS										
	Electricity Sale £/MWh		38			Inflation Rate %		2		
	Condensate Sale £/bbl		60			Exchange Rate US$/£		$1.50		
Cash Flow										
	Mean Production		Revenue							
Year	Gas	Condensate	Gas	Cond.	OPEX	CAPEX	Royalty	PRT	Corporation	TOTAL Field
	mmcfd	000 bbl/d	£M	£M	£M	£M	£M	£M	Tax £M	Cash Flow £M
0	0	0	0.0	0.0	0.0	424.7	0.0	0.0	0.0	-424.7
1	38	1.6	67.0	31.4	17.3	0.0	0.0	0.0	0.0	81.2
2	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	19.3	62.0
3	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	19.5	61.8
4	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	19.7	61.5
5	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	19.9	61.3
6	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	20.1	61.1
7	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	20.4	60.9
8	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	20.6	60.7
9	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	20.8	60.4
10	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	21.0	60.2
11	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	21.3	60.0
12	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	21.5	59.8
13	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	21.7	59.5
14	38	1.6	67.0	31.4	17.2	0.0	0.0	0.0	22.0	59.3
15	38	1.6	67.0	31.4	17.2	12.7	0.0	0.0	18.4	50.2
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
Present Values, at		5%	713.2	334.5	184.0	430.8	0.0	0.0	191.8	241.1

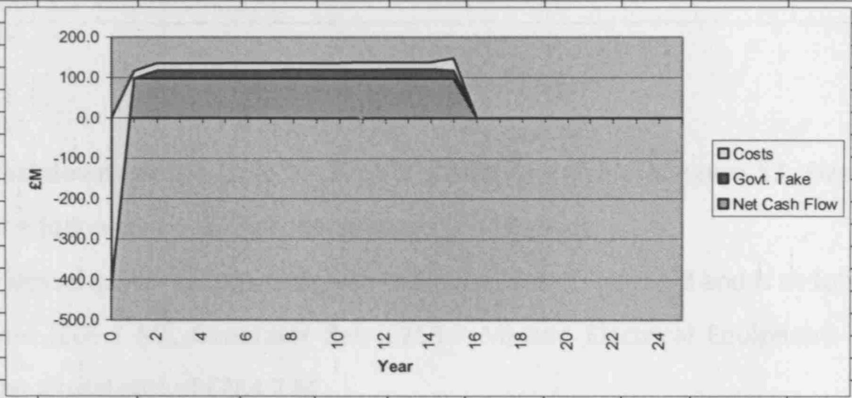
Figure 54 Economic Analysis (Page 2)

Discount	Total PV	Total PV	Total Gov.	Total Gov.
Rate	Post Tax	Pre Tax	Take	Take
%	£M	£M	£M	%
0	495.2	781.4	286.3	36.6
5	241.1	432.9	191.8	44.3
10	84.5	220.0	135.6	61.6
15	-17.1	83.2	100.3	-
20	-86.1	-9.1	77.0	-
25	-134.9	-73.8	61.1	-

Post Tax IRR %	13.97
Pre Tax IRR %	19.42
Payback Period (yrs)	6.6

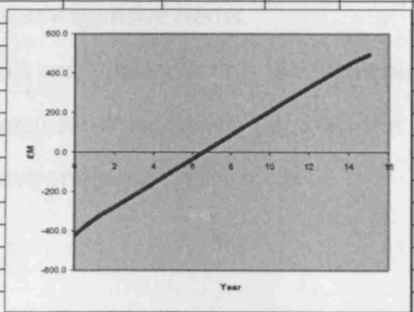
Revenue Split

Undiscounted



Cumulative Net Cash Flow

Undiscounted



Discounted at 5%

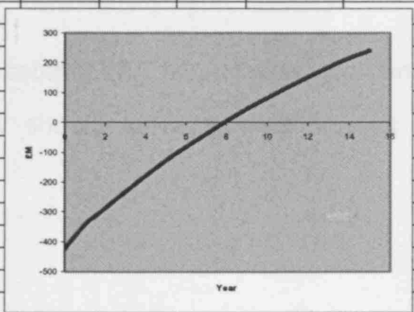


Figure 55 Economic Analysis (Page 3)

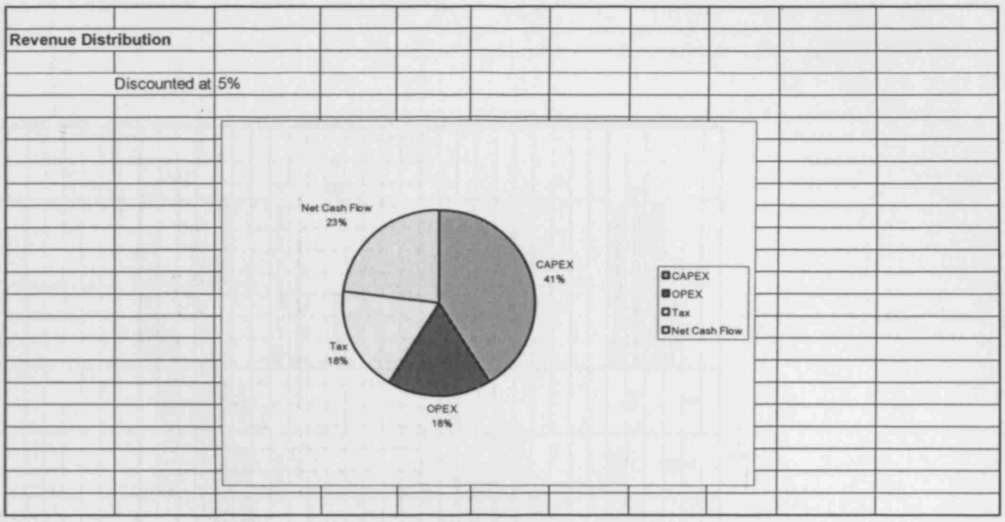


Figure 56 Economic Analysis (Page 4)

The cost breakdown for the Base Case CEPV scenario is given in Figure 57, Figure 58 and Figure 59. The following additional observations can be made:

- The vessel cost breakdown is given in Figure 57 and Figure 58 and is as follows; Basic Vessel (£66.3 M), Generator Set (£153.7 M) and Electrical Equipment (£44.2 M) giving a total cost of £264.2 M.
- Of the remaining costs the drilling for two new wells (£56.1 M), the electrical transmission cable (£57.5 M) and the onshore converter stations (£44.2 M) are the most expensive items.
- The cost of recovering the transmission cable (£12.7 M) is taken into consideration because it is envisaged that the CEPV should leave minimal impact upon the environment at relocation.

CASE NAME :	BASE CASE				
Location	1	2	3	4	5
Distance to Shore (km)	150	-	-	-	-
Recoverable Reserves					
gas (bn m^3)	8	-	-	-	-
liquids (bbl)	11.3	-	-	-	-
Vessel :-	Monohull				
Gen. Set :-	4 x Rolls-Royce Trent Combined Cycle, total 264 MW gross output				
Sequestration :-	None				
Transmission :-	DC; ICR (Aluminium, paper)				
Shore :-	Grid connection				

COST BREAKDOWN	CAPEX											OPEX (First Year)				
			MATLS &	FAB &					BASE							
ITEM	CAPEX BASIS		EQUIP	INSTALL	CONSTR.	EPCS	OP	INSUR.	CONSTR.	CONT.	TOTAL	COSTS	CONT.	TOTAL	OPEX BASIS	
			£M	£M	£M	£M	£M	£M	£M	£M	£M	£M /yr	£M /yr	£M /yr		
VESSEL																
A. Basic Vessel	E numeral based on dimensions gives					15%	5%	5%		25%			15%		Flat rate, based on 250 MW ship	
	steelweight and steel cost £/t.		40.4	4.5	44.9	6.7	2.2	2.2	56.2	10.1	66.3	0.8	0.1	0.9	design manning levels :-	
	Cost based on E num., outfit weight,															
	DP equipment and Processing Plant.														Complement	20 - 30
	L m	185														
	B m	35														
	T m	13														
	D m	19														
	E numeral	10,618														
	Steelweight t	13,448														
	Outfit weight t	2,590														
	Steel cost £/t	1,348														
	Base cost = Steelweight x steel cost															
	+ 10.4 x length x outfit weight £M															
	DP Equipment £M	3														
	DP Control £M	10														
	Processing Plant £M	6														
	Installation 50% of equipment cost															
B. Generator Set	Formulae derived from survey of			50%		15%	5%	5%		15%			15%		ABB maintenance schedule,	
	manufacturers' quoted prices per unit:-		71.3	35.6	106.9	16.0	5.3	5.3	133.6	20.0	153.7	7.7	1.1	8.8	spread evenly over project, with	
	Gas turbine, WHRU, steam turbine,														multiplier for aero-derivatives.	
	condensers, generators.												0%		Plus any fuel costs	
	(See Input Data sheet)											0	0	0		
	Installation 50% of equipment cost															

Figure 57 Costs (Page 1)

ITEM	CAPEX BASIS	MATLS & EQUIP	FAB & INSTALL	CONSTR.	EPCS	OP	INSUR.	BASE CONSTR.	CONT.	TOTAL	COSTS	CONT.	TOTAL	OPEX BASIS
		£M	£M	£M	£M	£M	£M	£M	£M	£M	£M /yr	£M /yr	£M /yr	
C. Sequestration Plant	Based on multiple of generating plant		50%		15%	5%	5%		15%			15%		Based on multiple of generating plant
	CAPEX (60%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.0**	0.0	0	0.0	OPEX (60%)
D. Electrical Equipment	Converters if DC transmission		20%		15%	5%	5%		15%			15%		
	0.125 £M x Voltage (kV)	25.6	5.1	30.8	4.6	1.5	1.5	38.4	5.8	**44.2**	0	0	0	
	Transformers													
	0.025 x Converter cost													
	Electrodes													
Subtotal		137.3	45.3	**182.6**	27.4	9.1	9.1	**228.2**	35.9	**264.2**	**8.5**	1.3	**9.7**	
WELLS	Number Drilled, 14 £M per prod. well				15%	5%	5%		15%			15%		
	(Including sequestration if applicable)	39.0	0	39.0	5.9	2.0	2.0	46.8	7.3	**56.1**	0	0	0	
	Includes subsea installations													
	+11 £M per abandoned well													
RISERS	2 £M per riser (90 m depth)				15%	5%	5%		10%			15%		
	(Including sequestration if applicable)	2.0	0	2.0	0.3	0.1	0.1	2.5	0.3	**2.8**	0	0	0	
CABLE	Raw Materials plus construction cost				15%	5%	5%		25%			15%		Flat rate per km based on cable
	(multiplier, x4), dependent on cable type	22.0	14.8	36.8	5.5	1.8	1.8	46.0	11.5	**57.5**	0.015	0.00	0.02	cores
	and AC/DC transmission.													
	Installation 67% of cable cost													
ONSHORE	Converters if DC transmission		20%		15%	5%	5%		15%			15%		
	0.125 £M x Voltage (kV)	25.6	5.1	30.8	4.6	1.5	1.5	38.4	5.8	**44.2**	0	0	0	
	Transformers													
	0.025 x Converter cost													
CONNECTIONS	Connection charges if connected to grid				15%	5%	5%		20%			15%		Grid connection and balancing
	(at start)	0.04	0	0.04	0.01	0.00	0.00	0.05	0.01	**0.06**	2.5	0.4	2.9	services charges (charges
														decrease slightly during project).
MISCELLANEOUS					15%	5%	5%		15%			15%		Insurance
		0.0	0	0.0	0.0	0.0	0.0	0.0	0	**0.0**	2	0.3	2.3	
												15%		Miscellaneous and admin
											2	0.3	2.3	

Figure 58 Costs (Page 2)

ITEM	CAPEX BASIS	MATLS & EQUIP	FAB & INSTALL	CONSTR.	EPCS	OP	INSUR.	BASE CONSTR.	CONT.	TOTAL	COSTS	CONT.	TOTAL	OPEX BASIS
		£M	£M	£M	£M	£M	£M	£M	£M	£M	£M /yr	£M /yr	£M /yr	
RELOCATIONS	Drilling (incl. sequestration if applicable)				15%	5%	5%		15%			15%		(Vessel running costs continue
		0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0	0	0	throughout project.)
	Risers				15%	5%	5%		10%					
		0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				
	Cable purchase				15%	5%	5%		25%					
		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				
	Cable recovery				15%	5%	5%		25%					
	(Cable recovery cost = 40% of new cable	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				
	cost)													
	Vessel transit				15%	5%	5%		15%					
		0.0	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0				
	Connection				15%	5%	5%		20%					
		0.00	0	0.00	0.00	0.00	0.00	0.00	0.00	0.00				
FINAL	Cable recovery				15%	5%	5%		15%			15%		
		8.8	0	8.8	1.3	0.4	0.4	11.0	1.7	12.7	0	0	0	
TOTAL		234.8	65.1	300.0	45.0	15.0	15.0	375.0	62.4	437.4	15.0	2.3	17.3	

Figure 59 Costs (Page 3)

6.6 Verification and Validation of the Economic Model

Verification and Validation (V & V) are the processes used to check that a software model meets its original specifications, fulfils its intended purposes, and gives meaningful results. Verification is a low level check to ensure that the software model satisfies the original specifications and gives reasonably acceptable output data and this is normally achieved using static (hand) testing. Validation is a high level check to ensure that the model is fit for purpose giving a high level of confidence in its output data and this is normally achieved through dynamic testing.

The Economic Model described in this chapter was built so that it presents comparatively to standard economic models developed and used by oil and gas operators when evaluating the profitability of exploiting offshore gas reserves by pipeline139. It is however a new type of economic model that has not been developed before hence it has some unusual characteristics.

Verification of the Economic Model was achieved by breaking the model down into its constituent parts. In other words parts of the model were tested independently by checking output data against hand calculations to ensure that the same results were achieved. For example, CAPEX calculations were simply checked by ensuring that the model summed the component costs of the CEPV scenario correctly using the cost data that was provided by manufacturers and equipment suppliers, and that these matched long hand calculations. When calculating the Cash Flow using the Discount Rate, great care was taken to ensure that the figures produced by the Economic Model matched hand calculations for both OPEX and Revenue. Furthermore, the model was checked so that the technical scenarios defined in the Input Page were reflected correctly across to the Output Page i.e. via the Calculation Page, and that the CAPEX reflected specified and realistic technical arrangements e.g. converter stations not required in AC transmission, CO_2 sequestration cost only included when specified, efficiency calculations were realistic i.e. between 30 and 65 %.

Validation of the model proved to be more difficult as data was not readily available for any similar scenario that could be used to compare with the data obtained from the Economic Model. However, the following steps were undertaken:

- The vessel costs were reviewed by the Professor of Naval Architecture at UCL and also by a major shipping company that has experience in the oil and gas field. It was concluded that the estimated costs of the CEPV were realistic.
- Output data was compared to similar scenarios where that was considered possible such as the electrical transmission arrangements i.e. CEPV transmission can be compared to similar length transmission systems used by National Grid networks[51].
- The Economic Model was reviewed by major oil and gas company who provided advice and recommendations for improvement to the model as it was built. The reviewer was an economist and he was satisfied that the Economic Model were of standard form used for costing oil and gas projects. Several modifications were recommended to improve the Economic Model which includes using EPCS for basic vessel costing, estimation for the costs of CO_2 sequestration and CEPV relocation.

The Economic Model is nevertheless only a model and although functionally correct it can not be properly validated unless a CEPV system is actually built. Nevertheless, the model does give economic data which provides a good indication of the likely returns on the investment made with a reasonable level of confidence.

6.7 Summary

This chapter has been concerned with the design and development of a computer based Economic Model for the CEPV which has then been used to examine its feasibility.

The Economic Model has been built within Microsoft Excel and was designed such that it presents comparatively to standard economic models developed and used by oil and gas operators when evaluating the profitability of exploiting offshore gas reserves by pipeline. The Economic Model is a DCF model based upon NPV to establish CAPEX, OPEX, NPV, IRR, and PP. Verification and validation of the Economic Model has been carried out, as far as it was possible to do so, by comparing results with hand calculations, similar scenarios where available, and by acting on feedback provided by an economist within the oil and gas industry.

The Base Case CEPV scenario was defined as being a mono-hull vessel having a 264 MWe CCGT Plant that exports HVDC electricity via a subsea cable to the National Grid network. The CEPV is located at an offshore gas field 150 km from shore that has sufficient gas for the whole of the project period (15 years). CO_2 sequestration was not selected for the Base Case to allow a more detailed investigation on the costs and revenues associated with using this technology, which is covered in the next chapter.

The commercial feasibility of the Base Case CEPV has been assessed using the Economic Model. The Base Case CEPV was shown to cost £437.4 M (CAPEX) with the major expense being the CCGT Plant, whilst annual operating costs (OPEX) were found to be £17.2 M. The IRR was found to be 19.42 % Pre-Tax or 13.97 % Post-Tax with a PP of 6.6 years.

The results seem to indicate, that despite the high initial investment, there is a reasonable financial return for the Base Case CEPV scenario. The CEPV can be compared with an alternative investment in a shore based gas-fired power station, which is known to cost £180 M (CAPEX)[151]. The difference in CAPEX between the CEPV and the shore based power station is accounted for by the additional costs of a gas processing plant, subsea electrical transmission system and a vessel that is needed to house the plant in the CEPV, as compared to a low cost building for a shore based power station which receives its gas post processing by the gas industry. In terms of OPEX then the additional costs of operating a power station at sea includes higher manning costs and lower plant efficiency i.e. longer transmission lines to the National Grid and higher onboard electricity use, which is offset by using stranded gas which is considered to be free. This compares to a shore based power station that uses processed gas for which it is charged but has lower manning costs and is located close to the National Grid.

The next steps in the investigation of the economics of the CEPV are to consider the effect of changing particular aspects of the CEPV operations i.e. moving away from the Base Case scenario investigated in this chapter. This includes examining the effects of changing financial circumstances, CEPV designs, field characteristics, revenues and costs associated with CO_2 sequestration.

7 Sensitivity Analysis for the Base Case CEPV

7.1 Introduction

In this chapter, sensitivity analyses are undertaken using the Economic Model to examine the effect of changes in financial conditions and the CEPV technical specifications upon the economic viability of the CEPV concept.

The sensitivity analyses are undertaken by making changes to the Base Case CEPV described in the previous chapter. The purpose was to examine the effect of possible changes in international financial conditions e.g. fluctuations in oil price and in the Dollar/Pound exchange rate, national financial conditions e.g. electricity sale price, cost of capital and taxation rates, and in the CEPV's own financial arrangements e.g. gearing and discount rate. The sensitivity analyses also examine the economic impact of making changes to the Base Case CEPV's technical specifications. The technical changes are primarily concerned with using alternative types of electricity generating plant, the use of CO_2 sequestration, and variations to the Base Case field characteristics e.g. field size, gas characteristics and distance to shore. The results from the Economic Model for each change are compared with those results previously obtained using the Base Case CEPV scenario.

The Clair Field in the West of Shetland Islands and Bonga Field offshore Nigeria are examined as possible locations for the CEPV. The results from the Economic Model are examined in detail to ascertain the economic viability and operational issues at these locations.

7.2 Sensitivity Modelling of Variations to Base Case

In the following sections the results from the sensitivity analyses carried out using the Economic Model are presented for changes in financial conditions.

7.2.1 Inflation Rate and Interest Rate

The Inflation Rate and Interest Rate are not within the control of the operator of the CEPV however, an understanding of the effect of changes in these rates is necessary when considering financial risk.

Figure 60 shows the reductions in Post Tax IRR which occur as a consequence of an increasing Inflation Rate (CPI Rate) when the Interest Rates are 1, 2 and 3 % higher than the Inflation Rate. The differential between the UK national Inflation Rates and Interest Rates has varied significantly over the past five years (2002 – 2007) however it has remained within a 3 % margin over this period[152].

Consider the case when the Interest Rate is set at 3 % above the Inflation Rate. The Economic Model shows that the Post Tax IRR falls from 14.06 % to 13.79 % as the Inflation Rate increases from 1 % to 5 %. Now consider the case when the Interest Rate is set at 1 % above the Inflation Rate. The Economic Model shows that the Post Tax IRR falls from 13.95 % to 13.67 % across the same rise in inflation. Results for Interest Rates greater than 5 % are shown to indicate that these trends are non-linear but Inflation Rates over 10 % are probably unrealistic.

These small changes in IRR are due to the fact that Interest Rate payments are tax deductible whilst equity is taxed. It is for the same reason that a differential of 3 % between the Interest Rate and Inflation Rate will give a better IRR than a differential of 1 %. Should the tax rate be reduced to 0 % (i.e. no tax relief available) then the IRR is unaffected.

Further, IRR is affected negatively by an increasing Inflation Rate when the Interest Rate remains unchanged i.e. the differential between Inflation Rate and Interest Rate reduces. On the other hand, as Interest Rates increase with an unchanged Inflation Rate, the IRR is affected positively.

Figure 61 shows the PP for the same conditions described in Figure 7.1 i.e. same differentials between the Inflation Rate and Interest Rates. It is clear that the PP is only marginally affected.

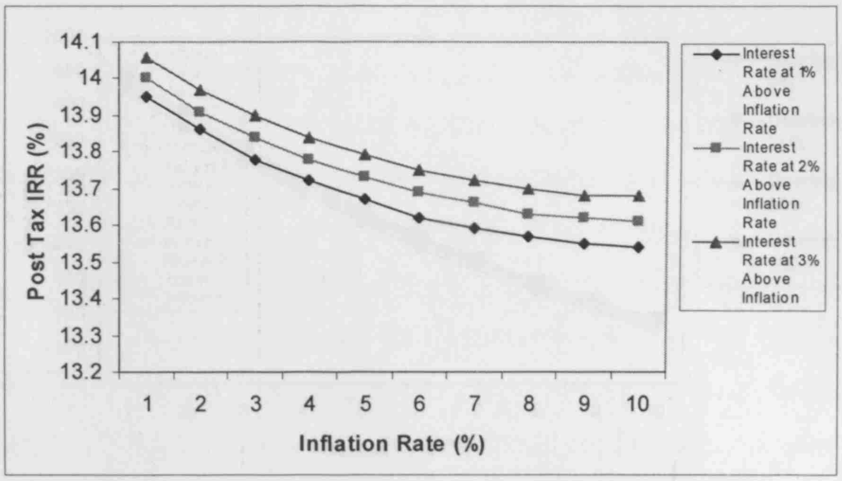


Figure 60 Sensitivity of Inflation Rate and Interest Rate on IRR

Figure 62 shows a reduction in NPV occurs as a consequence of increasing Interest Rates with different levels of Gearing. With Interest Rates of 10 %, it can be seen that the NPV is £249.8 M when the Gearing is 100 % and £233.7 M when the Gearing is zero. This represents a small percentage change (6.4 %) indicating that some attention would need to be paid to balance Gearing and Interest Rate levels to obtain the most favourable NPV for a given project.

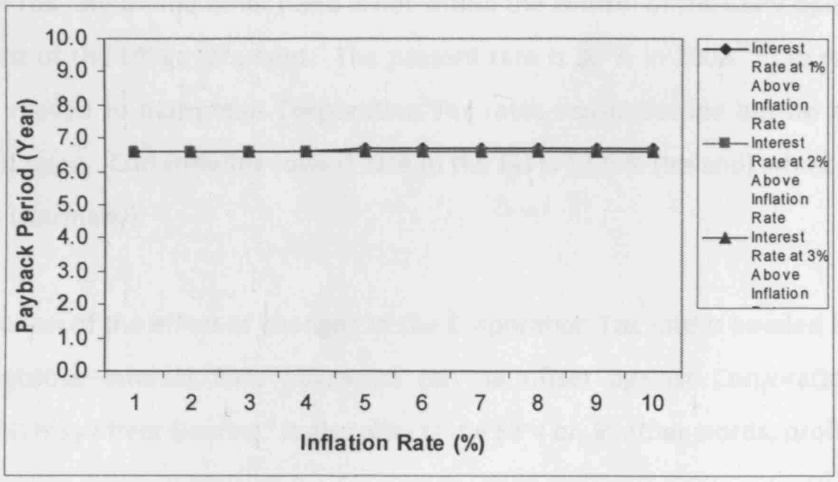


Figure 61 Sensitivity of Inflation Rate and Interest Rate on Payback Period

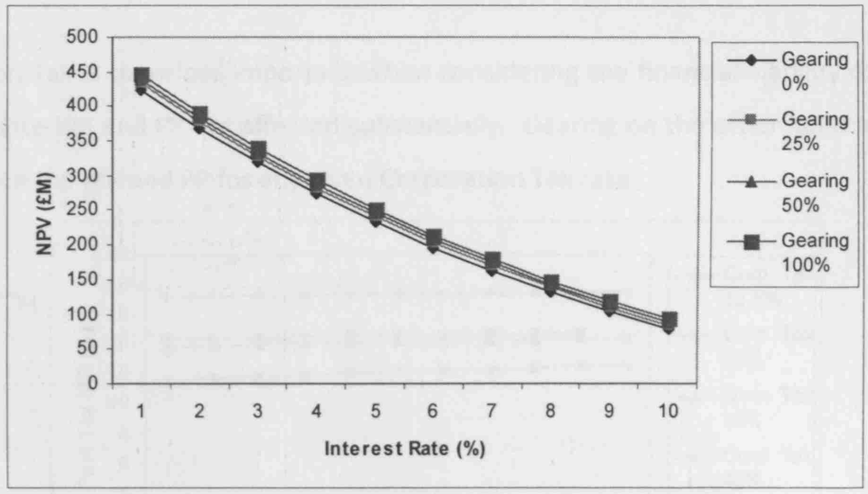


Figure 62 Effects of Changing Interest Rate upon NPV

7.2.2 Gearing and Corporation Tax

Gearing, the ratio of debt to equity, is within the control of the CEPV operator and may be varied theoretically between 0 and 100 % albeit a realistic Gearing ratio of around 25 % is more likely in order to share financial risk.

Corporation Tax rate on the other hand is not within the control of the CEPV operator and is at the behest of the UK government. The present rate is 30 % in 2008[153]. In recent years, the EU has moved to harmonise Corporation Tax rates across Europe but no rate has yet been agreed upon. Currently the lowest rate in the EU is 12.5 % (Ireland) whilst the highest rate is 40 % (Germany).

An appreciation of the effect of changes to the Corporation Tax rate is needed by the CEPV operator because Interest Rate payments can be offset against Corporation Tax and therefore this may affect Gearing. It also affects the NPV or, in other words, profit.

Consider the results shown in Figure 63 where changes to the Corporation Tax rate are plotted against the IRR and Gearing. It can be seen that IRR and PP is affected when Corporation Tax is changed from 20 to 40 % when the Gearing ratio remains unchanged. The effect is a reduction in IRR of 3.71 % and an increase in the PP of one year. However, when the Gearing ratio is adjusted then the effect of increasing corporation tax upon IRR and PP can only be slightly compensated for.

Corporation Tax is therefore important when considering the financial viability of the CEPV scenario since IRR and PP are affected substantially. Gearing on the other hand has a lower impact upon the IRR and PP for any given Corporation Tax rate.

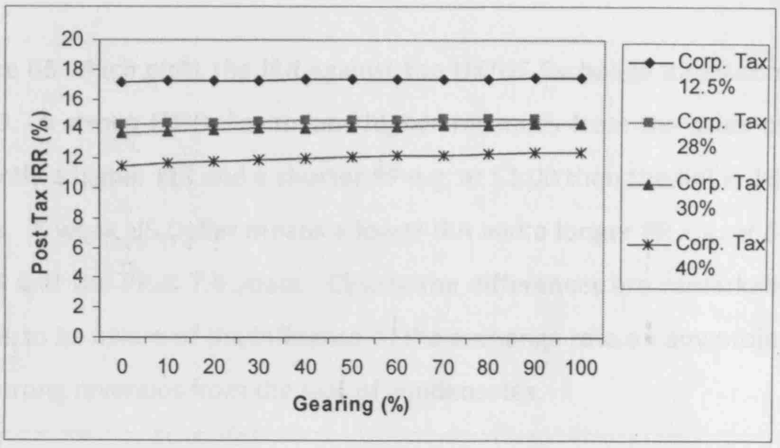


Figure 63 Sensitivity of Gearing and Corporation Tax on IRR

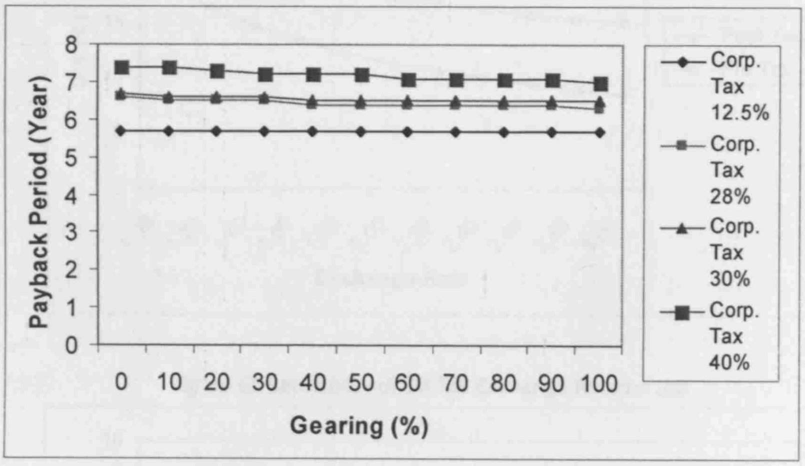


Figure 64 Sensitivity of Gearing and Corporation Tax on Payback Period

7.2.3 UK/US Currency Exchange Rate

The UK/US Exchange Rate has the potential to have a significant impact upon revenues when the CEPV exploits natural gas fields having a high condensate ratio. It was seen in the Base Case CEPV scenario that the revenue from the sale of condensate made up 31 % of the total revenue when the Condensate Ratio was 40 bbl/mmscf. The condensates recovered by the CEPV would be sold on the international market priced in US Dollars because these are petroleum products.

The UK/US Exchange Rate over the past ten years has ranged from \$1.40 to \$2.04[147]. Across this period the exchange rate has not been steady which for the CEPV operator means there is uncertainty in the revenues likely to be received from the sales of condensates.

Consider Figure 65 which plots the IRR against the UK/US Exchange Rates across a range of \$1.00 to \$3.00. A strong US Dollar means higher revenues from the sales of condensates and consequently a higher IRR and a shorter PP e.g. at \$1.00 then the IRR is 18.65 % and the PP is 5.4 years. A weak US Dollar means a lower IRR and a longer PP e.g. at \$2.00 then the IRR is 11.38 % and the PP is 7.4 years. Clearly the differences are remarkable. The CEPV operator needs to be aware of the influence of the exchange rate on any projects which rely heavily upon strong revenues from the sale of condensates.

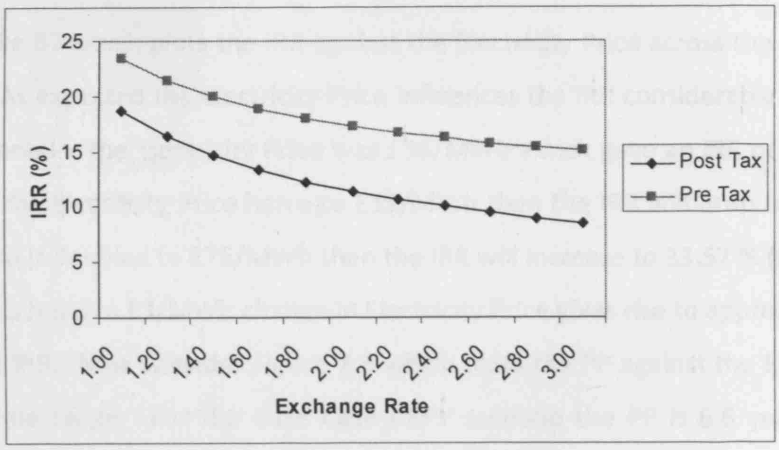


Figure 65 Sensitivity of UK/US Exchange Rate on IRR

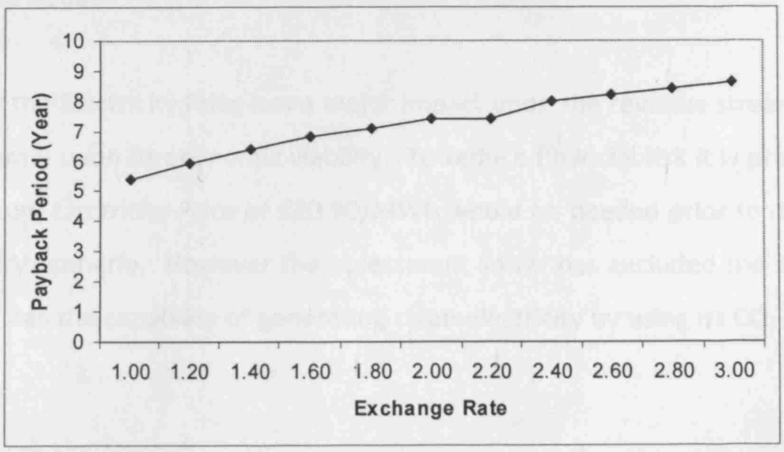


Figure 66 Sensitivity of UK/US Exchange Rate on Payback Period

7.2.4 Electricity Price

In the UK, electricity is a traded commodity and sales are regulated by BETTA, where the Standard Selling Price (SSP) and the Standard Buying Price (SBP) is determined on a half hourly basis[154]. These prices are affected by the supply and demand of electricity which varies from year to year, month to month, day to day and half-hour to half-hour. The selling price of generated electricity is therefore subject to market conditions and is difficult to quantify precisely. Electricity prices over the past 10 years have been as low as £15.70/MWh (average price 2003) and as high as £46/MWh (average price 2006)[145]. For the Base Case CEPV an average price of £38/MWh is used in the Economic Model. As the main revenue stream for the CEPV operator is from the sale of electricity then the effect of SSP changes on revenue need to be understood.

Consider Figure 67 which plots the IRR against the Electricity Price across the range of £20 - £100/MWh. As expected the Electricity Price influences the IRR considerably. For the Base Case CEPV scenario, the Electricity Price was £38/MWh which gave an IRR of 13.97 % (Post Tax). Should the Electricity Price halve to £19/MWh then the IRR will drop to 4.26 % (Post Tax) but should it doubled to £76/MWh then the IRR will increase to 33.57 % (Post Tax). The sensitivity is such that a £1/MWh change in Electricity Price gives rise to approximately 0.5 % change in the IRR. Now consider Figure 7.9 which plots the PP against the Electricity Price across the same range. For the Base Case CEPV scenario the PP is 6.6 years whilst this increases to 10.9 years should the Electricity Price half and reduce to 3.5 years should the Electricity Price double.

It is clear that the Electricity Price has a major impact upon the revenue stream of the CEPV and consequently upon its economic viability. To reduce financial risk it is probable that an agreed minimum Electricity Price of £20.90/MWh would be needed prior to developing the Base Case CEPV scenario. However the assessment so far has excluded the important fact that the CEPV has the capability of generating clean electricity by using its CO_2 sequestration plant.

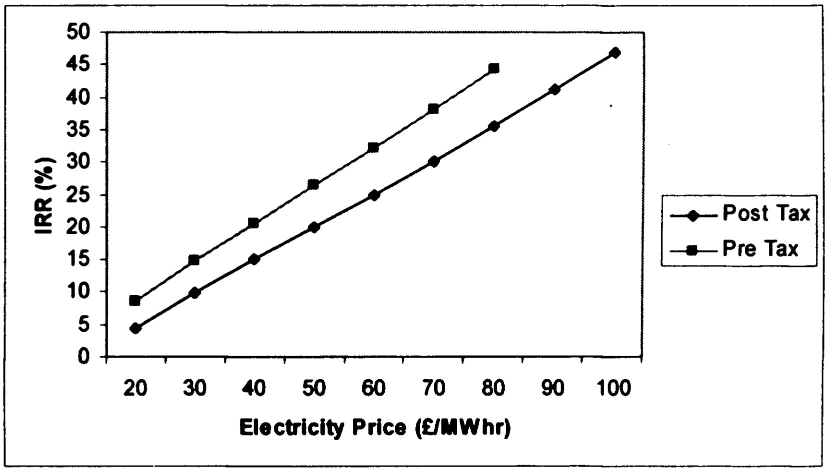


Figure 67 Sensitivity of Electricity Prices on IRR

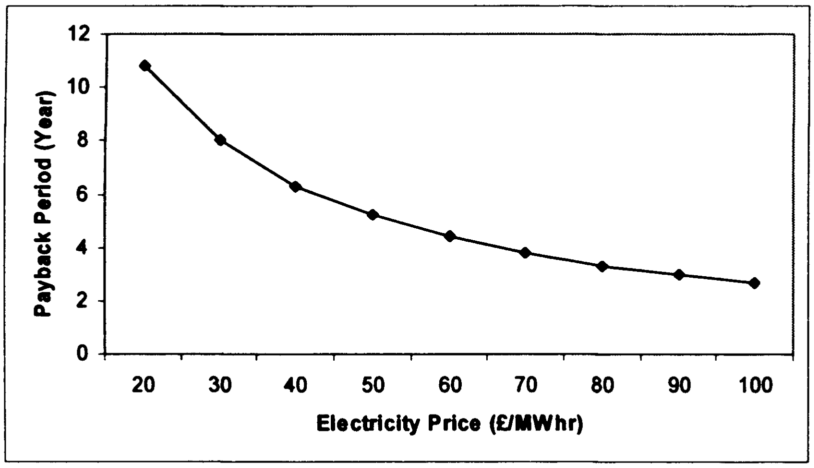


Figure 68 Sensitivity of Electricity Prices on Payback Period

7.2.5 Condensate Price

Condensate Price is the price obtained when selling the condensate products obtained during the processing of natural gas onboard the CEPV. The Economic Model considers condensates as being an additional source of revenue but this revenue stream is influenced by world oil prices which have been steadily rising from a low of $12/bbl in 1999 to in excess of $110/bbl in 2008[155] and every indication points to higher oil prices in the future[156]. The Base Case CEPV scenario exploited a natural gas field which had a condensate ratio of 40 bbl/mmscf with a sale price of $90/bbl which gave a strong revenue stream which amounted to 31 % of the total. Clearly condensate sales may influence the financial viability of the CEPV concept for a particular gas field.

Consider Figure 69 which plots the IRR against Condensate Price across the range of \$20 - \$200/bbl where the Electricity Price has remains unchanged at £38/MWh. As expected the Condensate Price influences the IRR considerably. For the Base Case CEPV scenario, the Condensate Price was \$90/bbl which gave an IRR of 13.97 % (Post Tax). Should the Condensate Price halve to \$45/bbl then the IRR will drop to 10.39 % (Post Tax) but should it double to \$180/bbl then the IRR will increase to 21.27 % (Post Tax). The sensitivity is such that a \$1/bbl change in Condensate Price gives rise to approximately 0.2 % change in the IRR. Now consider Figure 70 which plots the PP against the Condensate Price across the same range. For the Base Case CEPV scenario the PP is 6.6 years whilst this increases to 7.8 years should the Condensate Price half and reduce to 5 years should the Condensate Price double.

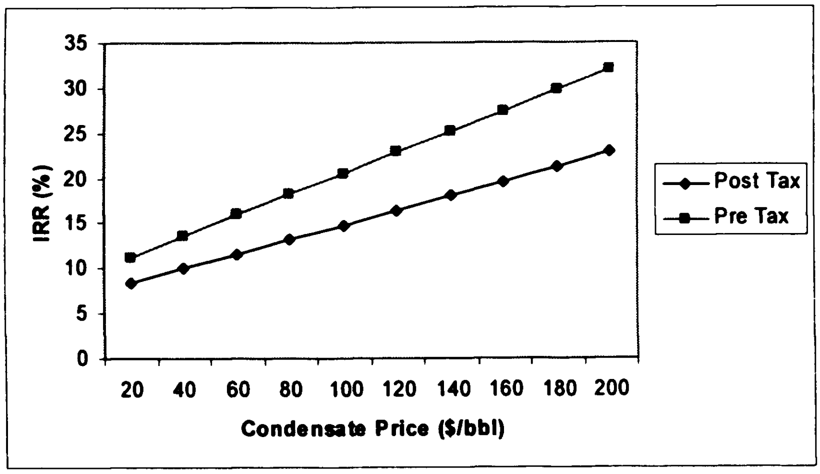


Figure 69 Sensitivity of Condensate Price on IRR

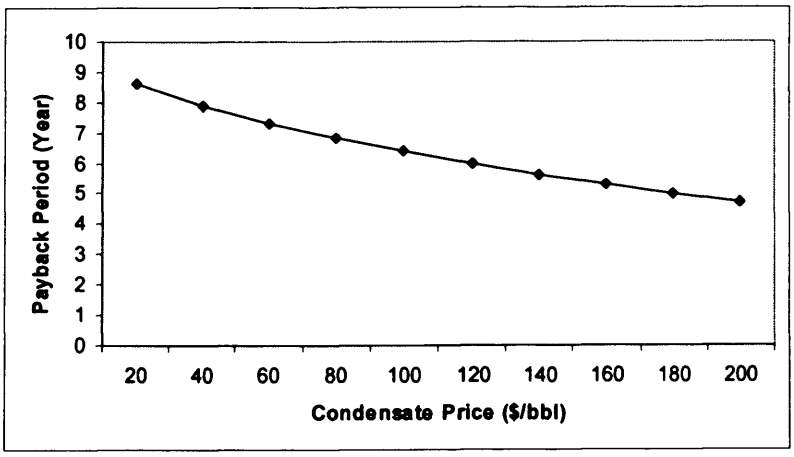


Figure 70 Sensitivity of Condensate Price on Payback Period

7.2.6 Electricity Price/Condensate Price

In the previous sections, Electricity Price and Condensate Price have been modelled independently to provide an understanding of the effect of each upon the IRR and PP. However, realistically, these two variables are inseparable because oil price also affects electricity price i.e. the energy prices are related because the majority of electricity is generated using fossil fuels (i.e. gas fired and coal fired power stations)[157]. It is important that the CEPV operator understands how this relationship affects revenue.

Consider Figure 71 and Figure 72 which plot the IRR and PP respectively against Electricity Price and Condensate Price together across the range of £20 - £100/MWh and $20 - $200/bbl (£13.33 - £133.33/bbl) where both prices rise proportionately. The Electricity to Condensate Price ratio was set at 0.6 bbl/MWh.

The results show the significant effect upon IRR of changing sales prices. The Base Case CEPV scenario, where the Electricity Price was £38/MWh and the Condensate Price was $90/bbl, gave an IRR of 13.97 % (Post Tax). Should the prices halve then the IRR reduces to 0.16 % with a PP of 14.7 years but should the prices double then the IRR increases to 42.19 % and PP reduced to 2.9 years.

Figure 73 expands upon the previous discussions and shows the effect upon IRR of different Condensate Ratios whilst keeping the Electricity to Condensate Price ratio constant at 0.6 bbl/MWh i.e. changing the amount of condensate that is available for sale from the natural gas processing.

Consider the case when the Electricity Price is £76/MWh and the Condensate Price is $180/bbl i.e. prices are double the Base Case CEPV scenario. It can be seen that a doubling of the Condensate Ratio to 80 bbl/mmscf will give an IRR of greater than 50 % and a PP of 2.1 years whilst a Condensate Ratio of zero will give an IRR of 25.83 % and a PP of 4.3 years.

Consider now the case when the Electricity Price is £19/MWh and the Condensate Price is $45/bbl i.e. prices are half the Base Case CEPV scenario. It can be seen that a doubling of the Condensate Ratio to 80 bbl/mmscf will give an IRR of 4.26 % and a PP of 10.9 years whilst a Condensate Ratio of zero results in negative IRR.

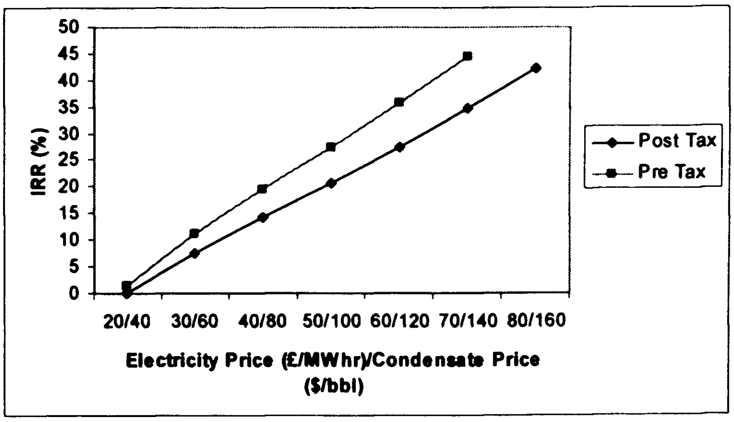


Figure 71 Sensitivity of Electricity and Condensate Prices as Related Commodities on IRR

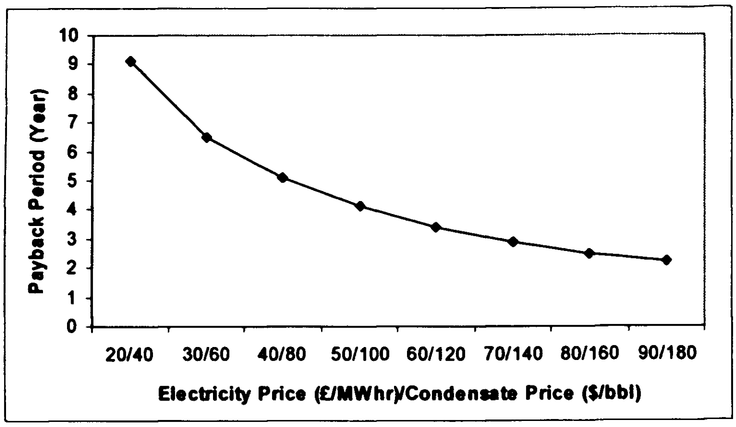


Figure 72 Sensitivity of Electricity and Condensate Prices as Related Commodities on Payback Period

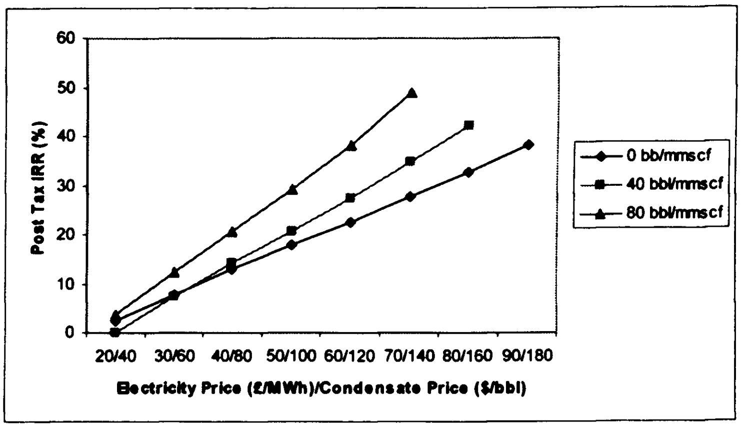


Figure 73 Effect of Condensate Ratio upon IRR

7.2.7 Distance to Shore and Water Depth

Distance to Shore and Water Depth has a direct impact upon the costs of the CEPV. Longer distances to shore across deep water translates into a longer transmission distance e.g. greater cable lengths and longer laying times, greater transmission losses, longer and deeper gas risers and CO_2 down-pipes. The impact financially is greater CAPEX and OPEX.

Figure 74 and Figure 75 show the impact upon the IRR and the PP of an increasing Distance to Shore and Water Depth, where the water depth increases with distance from shore at a rate of 0.6 m/km. This assumption has been made to simplify the modelling process although it is recognised that this may well not be the case in practice. A further assumption is the topology of the seabed remains unchanged.

The Base Case CEPV scenario indicated a Post Tax IRR of 13.97 % and a PP of 6.6 years where the transmission distance was 150 km and the water depth 90 m. Halving the Distance to Shore with water depth reducing to 45 m gives an IRR of 16.18 % and a PP of six years. Doubling the Distance to Shore increases the Water Depth to 180 m giving an IRR of 11.1 % and a PP of 7.5 years.

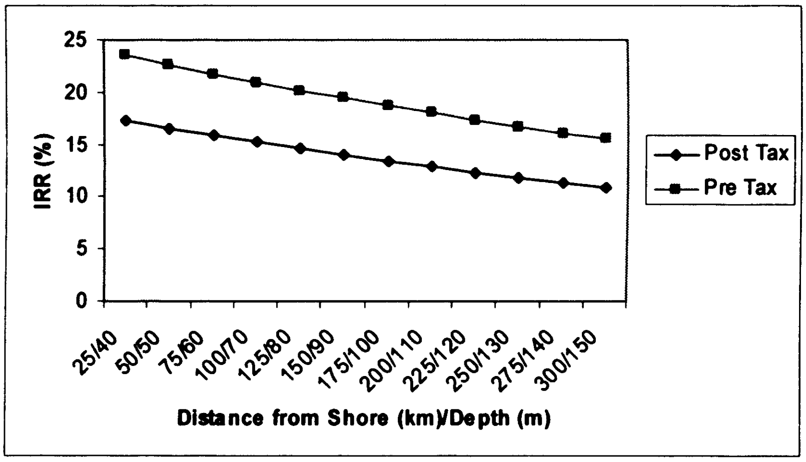


Figure 74 Sensitivity of Distance from Shore with Increasing Water Depth on IRR

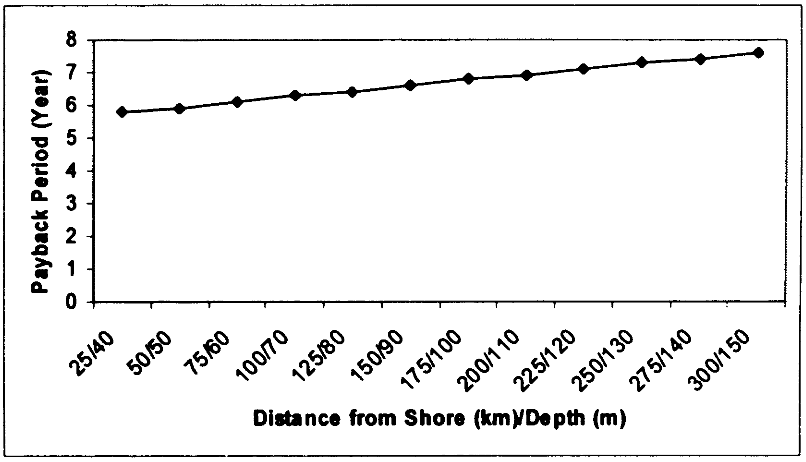


Figure 75 Sensitivity of Distance from Shore with Increasing Water Depth on Payback Period

There may be practical limits with regard to the distance from shore and the water depths the CEPV can safely operate in. For example the weight of the hanging cables could exceed the available buoyancy to produce sufficient force at the top end of the cable to give rise to vessel instability, and there are practical limits as regard to manning logistics and re-supply.

7.2.8 Relocation

The Economic Model is able to analyse the financial impact of relocating the CEPV to exploit a number of natural gas fields of different sizes and it allows the economic impact of the time taken to move the CEPV to a new natural gas field to be evaluated. Increasing the number of relocations increases CAPEX since new wells will need to be installed at each new gas field, additional cable installation will be required, and a change in the lengths of the gas risers and CO_2 down-pipes will also be likely. OPEX will also increase because there are periods of time, whilst the CEPV is being relocated, when revenue will be zero but crew and operating costs will still be incurred. The size of each natural gas field will affect the length of time the CEPV will operate at that gas field, whilst the number of wells used in each location will determine the maximum rate of natural gas production. Additional wells used in a natural gas field increase the gas production rate however the consumption of gas by the CCGT Plant is governed by its output power hence too many wells could incur additional CAPEX for no benefit. Two wells is probably a good economic compromise whereby each well is able to provide the CCGT Plant with its maximum demand for natural gas since this provides 100 % redundancy at a reasonable cost.

Consider Figure 76 and Figure 77 which plot the IRR and PP against zero, one, two and three relocations when two wells were used at each location. The Base Case CEPV scenario considered an 8 bn m^3 natural gas field which provided sufficient gas to maintain a mean gas flow of 40 mmscf/d as shown in Figure 78 which allows the CCGT Plant to operate at maximum output capacity across a 15 year period therefore a move to a new field is unnecessary.

Now consider the case of two fields each having 4 bn m^3 capacity (8 bn m^3 total). In this scenario the quantity of gas in the first field is insufficient to maintain the CCGT Plant at maximum capacity across the lifetime of the project as seen in Figure 79 where it is seen in year seven the CCGT Plant output must be reduced to cope with a drop in mean gas flow as the field's natural gas pressure falls. Moving the CEPV to the second field allows the CCGT Plant to resume operation at maximum capacity. However there is a period of six months when the CEPV is being moved during which revenue is zero. The consequence of this move is a reduced IRR from 13.97 % (Post Tax) to 11.32 % (Post Tax) whilst PP remains at 6.6 years. Now consider the case of three fields each having 2.67 bn m^3 capacity (8 bn m^3 total). In this scenario the quantity of gas at each field is also insufficient to allow the CCGT Plant to operate at maximum output capacity across the 15 year project period without moving. It can be seen in Figure 7.21 that during year for the CCGT Plant output must be reduced as the mean gas flow from the first field drops as its natural gas pressure falls. Moving to the second field allows the CCGT plant to operate again at maximum output capacity but during year ten the CCGT Plant output must be reduced again as both the mean gas flow and pressure in the second field fall. Moving the CEPV to the third field allows the CCGT Plant to resume operation at maximum capacity. In this scenario there are two periods of six months during which revenue is zero and the consequence is a further reduction in IRR and an increased PP to 8.13 % (Post Tax) and 8.8 years respectively.

Finally, consider the case of four fields each having 2 bn m^3 capacity (8 bn m^3 total). In this scenario the CEPV must be moved more regularly to allow the CCGT Plant to operate at near maximum capacity whilst on-site. Here there are three periods of six months during which revenue is zero and the consequence is a further reduction in IRR and increased PP to 3.81 % (Post Tax) and 11 years respectively.

It is clear that the IRR and PP are affected by relocating the CEPV particularly because of the lost revenue incurred during the move. This suggests that the CEPV should have a minimum number of moves which should be undertaken in the fastest possible time. However, moving the CEPV several times does not seem to make the venture uneconomic.

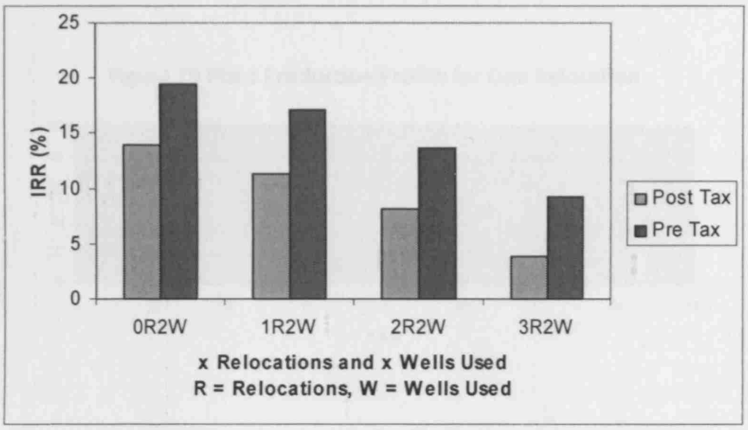


Figure 76 Sensitivity of No. of Relocation and No. of Wells Used upon IRR

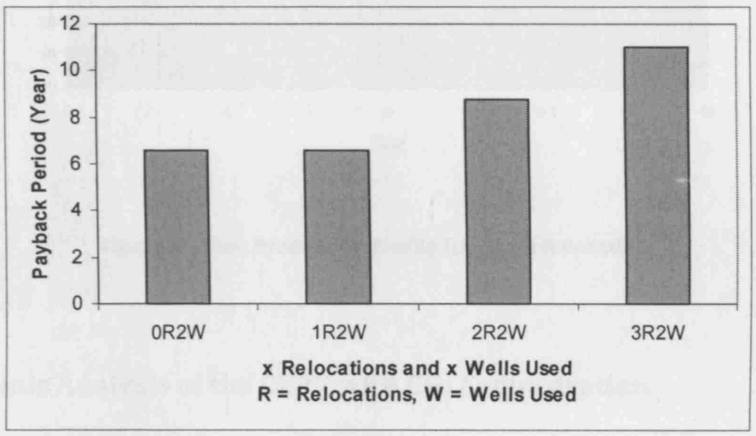


Figure 77 Sensitivity of No. of Relocation and No. of Wells Used upon Payback Period

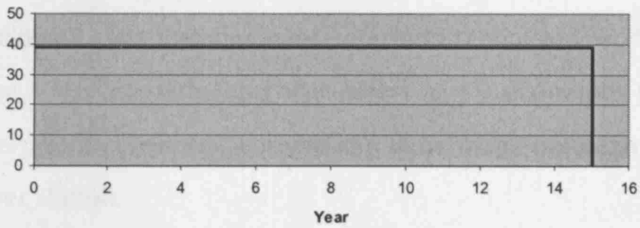


Figure 78 Plant Production Profile for No Relocation

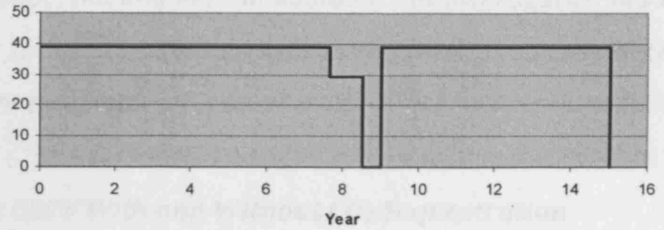


Figure 79 Plant Production Profile for One Relocation

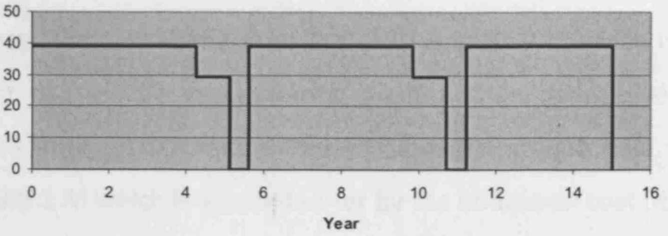


Figure 80 Plant Production Profile for Two Relocations

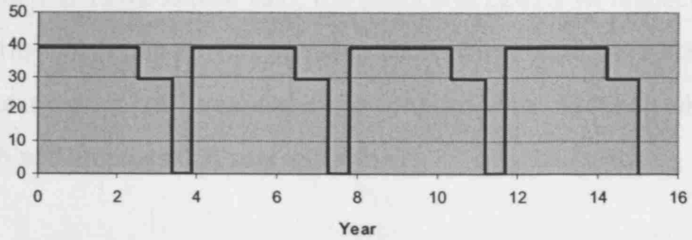


Figure 81 Plant Production Profile for Three Relocations

7.2.9 Economic Analysis of the CEPV with CO_2 Sequestration

In the previous section sensitivity analyses of the Base Case CEPV scenario were considered where the CO_2 sequestration plant was not used i.e. CCGT exhaust was emitted into the atmosphere. This allowed each financial parameter and technical specification to be varied from the Base Case CEPV scenario and the effect upon economic performance to be examined. It also permits an economic comparison to be made between an on-shore and an off-shore CCGT power station.

In this section, the Base Case CEPV has been re-configured to include use of the CO_2 sequestration plant i.e. there are no emissions to atmosphere. This CEPV scenario has been investigated so that the impact of CO_2 sequestration upon key financial parameters can be examined e.g. revenue, IRR and PP. In addition, this investigation has allowed the cost of CO_2 sequestration to be calculated as well as the level of subsidy necessary to make the 'green energy' CEPV competitive.

Base Case CEPV With and Without CO_2 Sequestration

Table 31 compares the economic performance of the Base Case CEPV scenario with and without CO_2 sequestration. The difference in CAPEX is £157.9 M which is accounted for by the additional cost of the CO_2 sequestration plant and its down-pipes and the subsea installation required to inject CO_2 into a disused oil or natural gas field. The difference in first year OPEX is £69.3 M which is accounted for by the additional cost of operating the CO_2 sequestration plant e.g. running the compressors, maintenance and consumables.

The IRR, PP, and NPV is 19.42 % (Pre Tax), 6.6 years and £241.1 M respectively for the Base Case CEPV scenario which has no CO_2 sequestration plant, whilst the IRR drops to 6.27 % (Pre Tax), the PP extends to 11.7 years and the NPV drops to -£57.3 M when the Base Case CEPV is fitted with and employs CO_2 sequestration.

Clearly, there is no financial advantage to use CO_2 sequestration since the results indicate that such a CEPV scenario is economically unviable unless there are tax advantages or subsidies for so doing.

Table 31 Comparison of Base Case CEPV Scenario With and Without CO_2 Sequestration

Parameter	Without CO_2 Sequestration	With CO_2 Sequestration
IRR (%)	19.42 (13.97)	6.27 (3.28)
PP (Years)	6.6	11.7
NPV (£M)	241.1	-57.3
CAPEX (£M)	437.4	595.3
First Year OPEX (£M)	258.4	327.7

Electricity Price

Consider Table 32 which gives the IRR and PP for the Base Case CEPV with and without CO_2 sequestration for Electricity Prices of £19/MWh, £38/MWh and £76/MWh. For the present Electricity Price of £38/MWh, the IRR is 6.27 % (Pre Tax) and 19.42 % (Pre Tax) with and without CO_2 sequestration, whilst the PP is 11.7 years and 6.6 years respectively. The IRR and PP values, should the Electricity Price halve to £19/MWh, are 7.8 % (Pre Tax) and 11.2 years for the Base Case CEPV without CO_2 sequestration, whilst the Base Case CEPV with CO_2 sequestration is economically unviable. The IRR and PP values, should the Electricity Price double to £76/MWh, are 41.84 % (Pre Tax) and 3.5 years respectively for the Base Case CEPV without CO_2 sequestration, whilst a Base Case CEPV with CO_2 sequestration are 19.12 % (Pre Tax) and 6.5 years respectively. Clearly the CO_2 sequestration is an additional cost which affects the economic viability of the CEPV significantly.

Consider Table 33 which compares the Electricity Prices that are needed by the Base Case CEPV with and without CO_2 sequestration to achieve similar IRR, and the amount of subsidy needed. It is clear that CO_2 sequestration is an expensive process requiring approximately 100 % subsidy e.g. for the present Electricity Price of £38/MWh a Base Case CEPV with CO_2 sequestration requires a subsidy of £39/MWh (102 %) to give an IRR of 19.42 % which is obtained by the Base Case CEPV i.e. when CO_2 sequestration is not used and electricity is sold at £38/MWh.

Now consider Table 34 which presents IRR values obtained from the Economic Model when the Base Case CEPV without CO_2 sequestration is charged a Carbon Tax and when the Electricity Price is £38/MWh. It can be seen that as the Carbon Tax increases the IRR falls. Comparing Tables 7.2 and 7.4 then it can be seen that a Carbon Tax of $71/tonne is required to bring the IRR of the Base Case CEPV without CO_2 sequestration but with Carbon Tax applied, in line with the Base Case CEPV with CO_2 sequestration. Obviously the cost of dealing with CO_2 i.e. using sequestration or levying Carbon Tax would be expensive to the CEPV operator.

Table 32 Variations in IRR and PP for Electricity Prices

Electricity Price	CEPV Without CO_2 Sequestration		CEPV With CO_2 Sequestration	
	IRR	PP	IRR	PP
£19/MWh	7.8 %	11.2 years	< 0	-
£38/MWh	19.42 %	6.6 years	6.27 %	11.7 years
£76/MWh	41.84 %	3.5 years	19.12 %	6.5 years

Table 33 Comparing Electricity Price for the Base Case CEPV With and Without CO_2 Sequestration to Achieve the Same IRR using Financial Subsidy

Electricity Standard Selling Price (SSP)	Base Case CEPV Without CO2 Sequestration Pre Tax IRR	Base Case CEPV with CO_2 Sequestration Price Needed to Achieve Pre Tax IRR	Subsidy Needed the Base Case CEPV with CO_2 Sequestration	Ratio of Subsidy to Standard Selling Price (SSP)
£19/MWh	7.8 %	£42/MWh	£23/MWh	121 %
£38/MWh	19.42 %	£77/MWh	£39/MWh	102 %
£76/MWh	41.84 %	£142/MWh	£74/MWh	97.3 %

Table 34 The Effect of Carbon Tax upon the IRR for the Base Case CEPV Without CO_2 Sequestration

Carbon Tax ($/tonne)	IRR
0	19.42 %
10	17.76 %
20	16.07 %
50	10.60 %
71	6.27 %

Electricity Price and Condensate Price

Consider Table 35which gives the IRR and PP for the Base Case CEPV with and without CO_2 sequestration Electricity and Condensate Prices (as related commodities) of £19/MWh and $45/bbl; £38/MWh and $90/bbl; and £76/MWh and $180/bbl. For the present Electricity and Condensate Price of £38/MWh and $90/bbl, the IRR is 6.27 % (Pre Tax) and 19.42 % (Pre Tax) with and without CO_2 sequestration, whilst the PP is 11.7 years and 6.6 years respectively. Should the prices halve to £19/MWh and $45/bbl, the Base Case CEPV with or without CO_2 sequestration is economically unviable. The IRR and PP values, should the Electricity Price double to £76/MWh and $180/bbl, are in excess of 50 % (Pre Tax) and 2.9 years respectively for the Base Case CEPV without CO_2 sequestration, whilst a Base Case CEPV with CO_2 sequestration are 26.64 % (Pre Tax) and 5.3 years respectively.

Table 35 Comparing Electricity and Condensate Prices as Related Commodities

Electricity and Condensate Price (£/MWh, $/bbl)	CEPV Without CO_2 Sequestration		CEPV With CO_2 Sequestration	
	IRR	PP	IRR	PP
19/45	1.34 %	-	< 0	-
38/90	19.42 %	6.6 years	6.27 %	11.7 years
76/180	> 50 %	2.9 years	26.64 %	5.3 years

Clearly the Base Case CEPV with and without CO_2 sequestration is more economically attractive when Electricity and Condensate Prices are high but if CO_2 sequestration is used the additional CAPEX and OPEX impacts significantly upon economic performance.

7.2.10 Generation Set Options and Vessel Design

A compendium of 14 electricity generator set options and their corresponding vessel designs is presented in Chapter Three. This database which is used by the Economic Model contains information on electricity generating plant configuration, plant efficiency, maximum output power, CAPEX, OPEX and emissions across a range of 157 MW to 502 MW. These data has been obtained from manufacturers as discussed in Chapter Three. The vessel design to house the different electricity generating plant was simply scaled using the Base Case CEPV as discussed in Chapter Five as is the subsea transmission cables and electrical transmission equipment as discussed in Chapter Four, and the CO_2 sequestration plant as discussed in Chapter Three.

In this section the economic viability of each electricity generator set option is investigated in order to understand the economic relationships between the electricity generating plant, CEPV vessel design and construction, and CO_2 sequestration.

Consider Figure 82 and Figure 83 which plot the IRR and PP against electricity generator set options with and without CO_2 sequestration, where the Financial Data, Field Data and the Transmission Type (i.e. DC transmission) remains the same as the Base Case CEPV scenario.

The best economic performance without CO_2 sequestration was achieved in Case 11 which represents a 400 MW CCGT generating plant consisting of four gas turbines rated at 66.5 MW each and four steam turbines rated at 37.5 MW each which is 33 % more expensive than the 264 MW CCGT Plant used in the Base Case CEPV scenario. This larger vessel has a CAPEX of £495.7 M which is 13 % more expensive than the Base Case CEPV vessel. The IRR for this scenario is 24.3 % (Post Tax) with a PP of 4.2 years. The second best in economic performance was Case 12 which represents a 502 MW CCGT Plant having eight gas turbines and four steam turbines.

The best economic performance with CO_2 sequestration is Case 1 which represents a 258 MW GT generating plant consisting of six gas turbines rated at 43 MW each which is 28 % cheaper than the 264 MW CCGT Plant used in the Base Case CEPV scenario. This smaller vessel has a CAPEX of £386.6 M and is 18 % cheaper than the Base Case CEPV vessel. The IRR for this scenario is 8.68 % (Post Tax) with a PP of 7.7 years. The second best in economic performance was Case 11 which was specified above for the scenario without CO_2 sequestration.

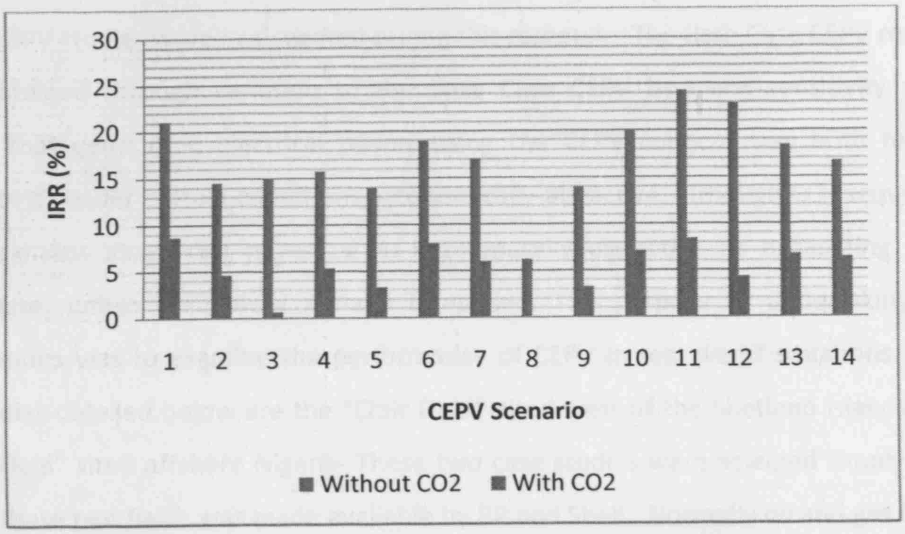


Figure 82 Sensitivity of Generator Set Options, Vessel Designs and CO_2 Sequestration on IRR

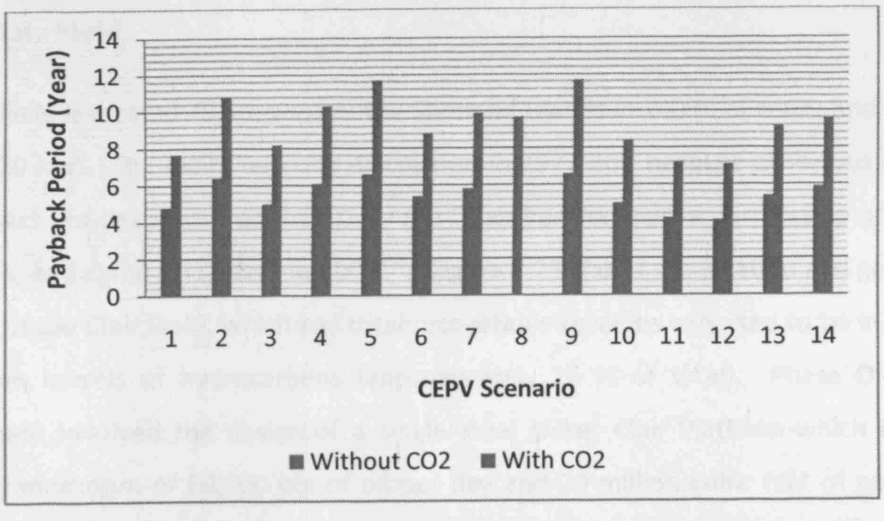


Figure 83 Sensitivity of Generator Set Options, Vessel Designs and CO_2 Sequestration on Payback Period

The selection process for the most suitable electricity generation plant will not depend solely upon IRR and PP because other factors will need to be carefully assessed for particular gas field scenarios including plant efficiency and emissions, output power required and maintenance needs. However, the results do show that a large plant capable of generating significant quantities of electrical power, thereby giving rise to substantial revenue early in the project to offset the CAPEX, is highly desirable.

7.3 Case Studies

Further to the Base Case CEPV developed, justified and investigated in Chapter Five, two further CEPV studies were investigated during this research. The Base Case CEPV results and those obtained through variation to the Base Case CEPV by using sensitivity analyses, showed that generating electrical power using the CEPV concept was both technically feasible and, under certain conditions, economically attractive, although CO_2 sequestration of the exhaust gases can never be as economically attractive as exhausting into the atmosphere, unless a financial penalty is applied. The purpose of undertaking further investigations was to examine the performance of CEPV in real world situations. The two case studies detailed below are the "Clair Field" sited west of the Shetland Islands and the "Bongo Field" sited offshore Nigeria. These two case studies were selected simply because data on these two fields was made available by BP and Shell. Normally oil and gas field data is highly sensitive and tightly guarded.

7.3.1 Clair Field

The Clair Field is located 75 km west of the Shetland Islands in 140 m of water and covers an area of 220 km^2. The Clair Field was discovered in 1977 but, because of various economic reasons, was not developed until 2001 by the "Clair Partnership", a partnership of major oil companies, and came on stream in 2005[158]. Figure 7.25 shows the location and geophysical structure of the Clair Field, which has total recoverable reserves expected to be in excess of 250 million barrels of hydrocarbons (approximately 15 % of total). Phase One of the development involved the design of a single steel jacket Clair Platform which is able to produce a maximum of 60,000 bbl of oil per day and 20 million cubic feet of gas per day using 15 oil producing wells, eight water injectors and one re-injection well[149]. It is also known that a large gas cap is present in the structurally elevated Ridge segments of the Clair Field but the exact quantity of gas contained within it is unknown[159]. The oil from Clair Platform is piped subsea to the Sullom Voe oil terminal on the Shetland Islands for processing and distribution, whilst the natural gas is either re-injected into the Clair Field or exported to the Magnus Field where the natural gas is used for Enhanced Oil Recovery. Depending upon the success of Clair Platform for oil production, the remaining parts of the Clair Field will be explored with the Clair Platform being used as a central hub.

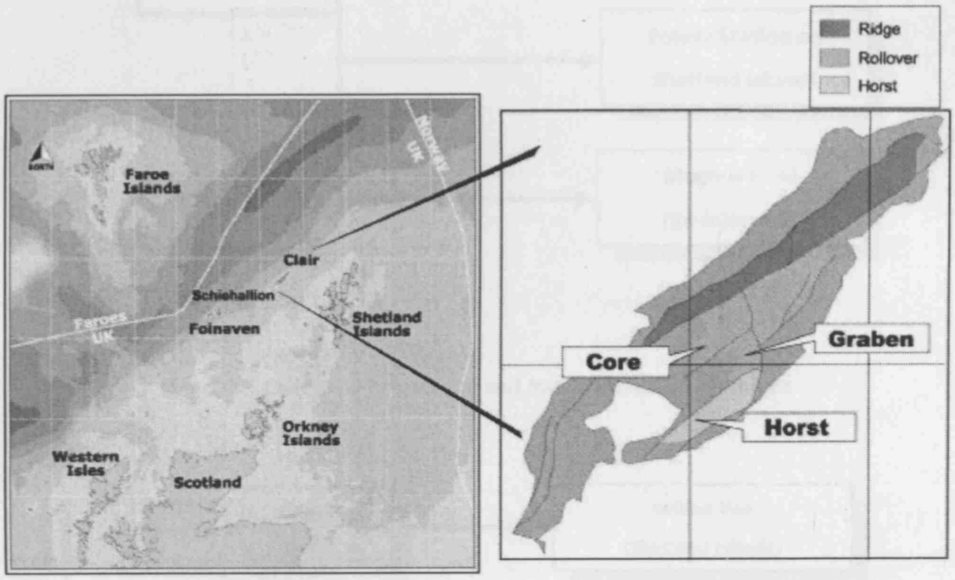


Figure 84 Location of the Clair Field in the West of Shetland Islands, North Sea[149]

Concept

The concept explored here is for the CEPV to use the natural gas generated on the Clair Platform during oil recovery, supplemented by the natural gas that is known to be present in the Clair Field gas cap. Therefore, the Clair Platform will export natural gas to the CEPV; the CEPV will use the natural gas to generate electricity which is exported via subsea cable to Dounreay in Northern Scotland; the CO_2 from the CEPV will be exported to the Magnus Field for re-injection for Enhanced Oil Recovery or back to the Clair Platform for re-injection there, in both cases affecting CO_2 sequestration. In the case where the CEPV needs to be shut down then the oil production on Clair Platform is uninterrupted because the gas system can be quickly reconfigured to the original arrangement. Figure 85 shows the existing oil and natural gas piping arrangements for the Clair Field whilst Figure 86 shows the proposed concept whereby the CEPV imports natural gas and exports electricity and CO_2.

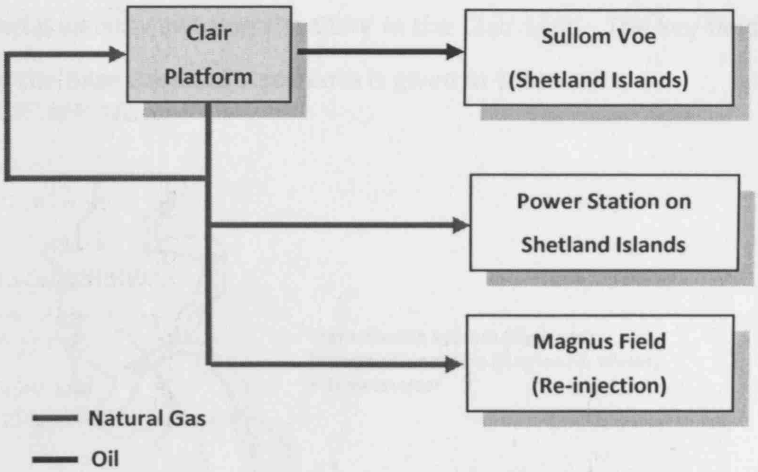


Figure 85 Clair Field Present Oil and Natural Gas Arrangements

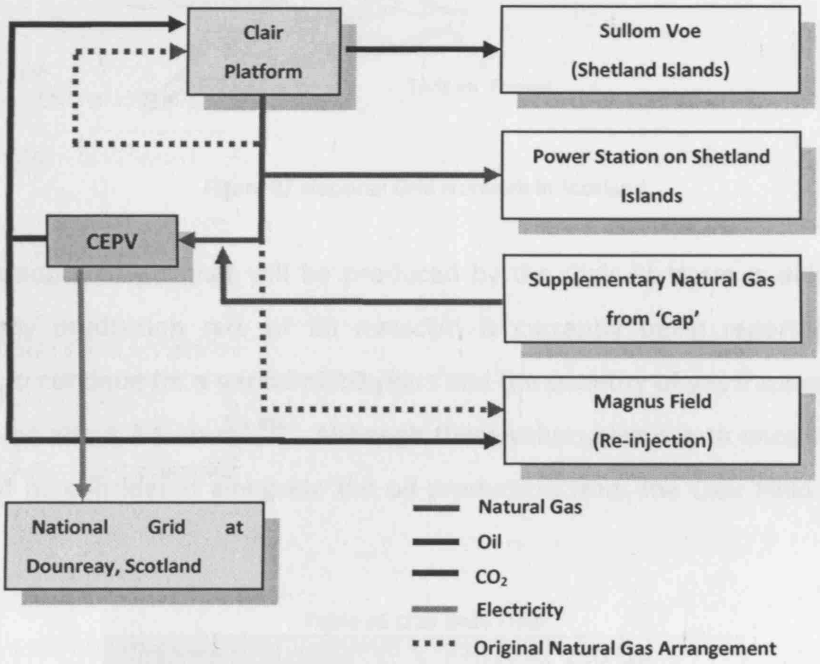


Figure 86 Clair Field Proposed Oil and Natural Gas Arrangement When Using CEPV

Exporting electricity to Dounreay in Northern Scotland has been chosen because it will allow the CEPV to connect to the National Grid. Dounreay is a coastal site that was previously home to several nuclear power stations which have since been shut down but the HVAC transmission infrastructure connecting to the National Grid remains in place[160] as seen in Figure 87.

Information provided by BP and other sources[149,158,159] was used by the Economic Model to examine the financial viability of using the CEPV in the Clair Field. The key field information which differs from the Base Case CEPV scenario is given in Table 36.

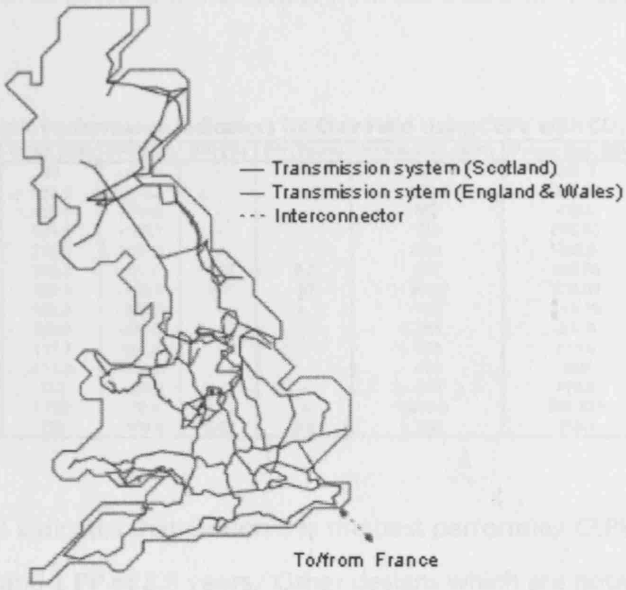


Figure 87 National Grid Network in Scotland

The total amount of gas that will be produced by the Clair Platform is unknown but an average daily production rate of 20 mmscf/d is currently being reported and this is forecasted to continue for a period of 10 years and the quantity of gas trapped in the cap is thought to be about 3.1 bn m^3 [158]. Although these values give rise to uncertainty and risk they should be considered alongside the oil production from the Clair Field which is also unknown.

Table 36 Clair Data Field

Distance to Shore (CEPV to Dounreay)	230 km
Water Depth	140 m
Predicted averaged daily natural gas production from Clair Platform	20 mmscf/d for 10 years
Field Cap Size (Estimated)	3.1 bn m3
Predicted Condensate Ratio	40 bbl/mmscf
No. of New Wells Drilled in Cap	2

Analysis

The Economic Model was used to analyse the 14 different CEPV concepts to establish appropriate designs that would give acceptable economic performance. CO_2 sequestration must be considered in all cases and the results from the Economic Model are given in Table 37.

Table 37 Economic Performance Indicators for Clair Field Using CEPV with CO_2 Sequestration

Options	CAPEX (£M)	OPEX (£M)	NPV (£M)	IRR (%)	PP (Years)	Power Gen. (MW)	Power Exp. (MW)	Viability	Ranking
1	553.4	93	-105.7	-	-	258	245.1		
2	633.7	132.5	-152.7	-	-	250.8	238.26		
3	1000.4	115.1	-446.9	-	-	502	476.9		
4	675.4	144.6	-145.1	-	-	279	265.05		
5	634.2	218.2	-187.3	-	-	264	250.8		
6	570.2	115.3	-67.5	1.87	8.8	267	253.65	Y	1
7	567.5	109.1	-106.9	0.1	10	263.2	250.04	Y	3
8	593.3	192.8	-323.1	-	-	157	149.15		
9	634.2	218.3	-187.3	-	-	264	250.8		
10	686.5	117.7	162.2	-	-	328	311.6		
11	727.5	111.9	-166.2	-	-	400	380		
12	865.7	112	-309.6	-	-	502	476.9		
13	573	179.2	-70.4	-	9	259.5	246.525		
14	589.7	125	-100.5	0.56	9.6	258	245.1	Y	2

The Economic Model indicates that Option 6 is the best performing CEPV design with an IRR of 1.87 % (Post Tax) and a PP of 8.8 years. Other designs which are potentially economically feasible are Options 7 and 14. However all options report a negative NPV.

Considering Option 6, which is a 267 MW General Electrics CCGT Plant that consists of two gas turbines rated at 83.5 MW each and one steam turbine rated at 100 MW, then it is necessary to have an additional payment for each MW of electricity generated in order to achieve a zero NPV. This rate of subsidy is £8.70/MWh (23%) above the current electricity SSP. Further subsidies beyond this level would result in a positive NPV. Assuming that a subsidy of £8.70/MWh is provided then it is interesting to examine the effect should the gas supply prediction change both positively and negatively.

Consider the effect upon IRR, PP and NPV of a change in the predicted gas supply from the Clair Platform. Figure 88 shows the range of IRR achievable should the gas supply change across a range of 10 to 30 mmscf/d whilst Figure 89 and Figure 90 show the PP and the NPV results respectively.

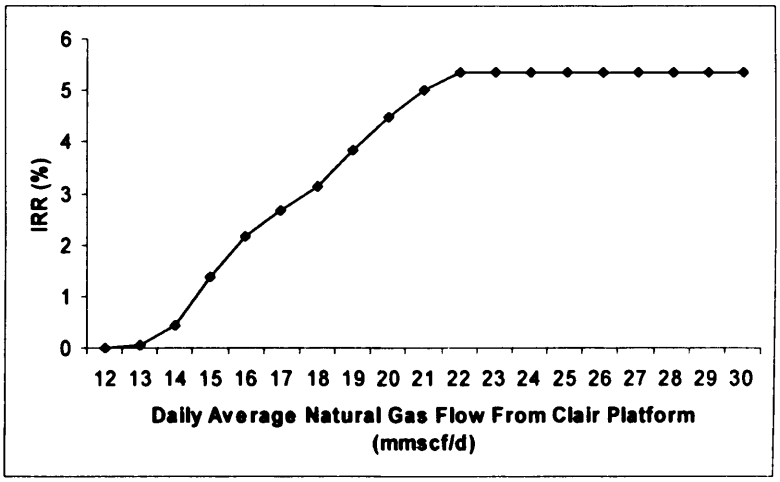


Figure 88 Effects of Changing Predicted Average Daily Gas Production from the Clair Platform upon IRR

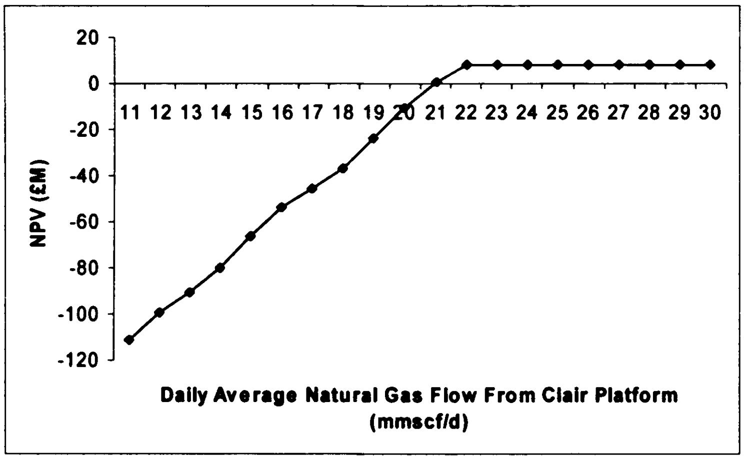


Figure 89 Effects of Changing Predicted Average Daily Gas Production upon NPV

Figure 88 shows that the maximum IRR achievable is 5.35 % because the CEPV is operating at maximum capacity (excluding maintenance shut down days) with an unrestricted natural gas supply which is made up from the Clair Platform and the gas 'cap' over a period of 10 years. Below 22 mmscf/d the IRR drops because the amount of gas received at the CEPV falls short of that required for operation at maximum plant capacity. This means the plant is working at a lower output hence the revenue stream is restricted. This restriction could be overcome by allowing the CEPV to operate at maximum plant capacity by demanding a greater supply of natural gas from the gas 'cap' in the earlier years thereby using this reserve more rapidly and reducing the lifetime of the project.

Now consider Figure 89 which shows the NPV with variation in the natural gas flow. It can be seen that the maximum NPV is £8.3 M and below 22 mmscf/d the IRR begins to fall and reaches zero at a predicted daily gas production rate of 20 mmscf/d.

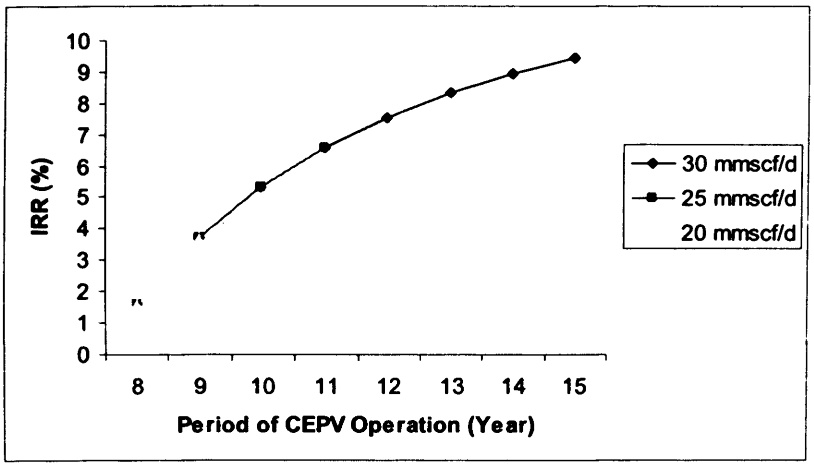


Figure 90 Effects of Changing Predicted Average Daily Gas Production and Length of Project upon IRR

Clearly for natural gas flows above 20 mmscf/d then the CEPV scenario as presented is economic and indeed a larger CEPV could have been used to increase returns. On the other hand, gas flows below 20 mmscf/d result in an increasingly difficult economic situation hence greater subsidies would need to be sought.

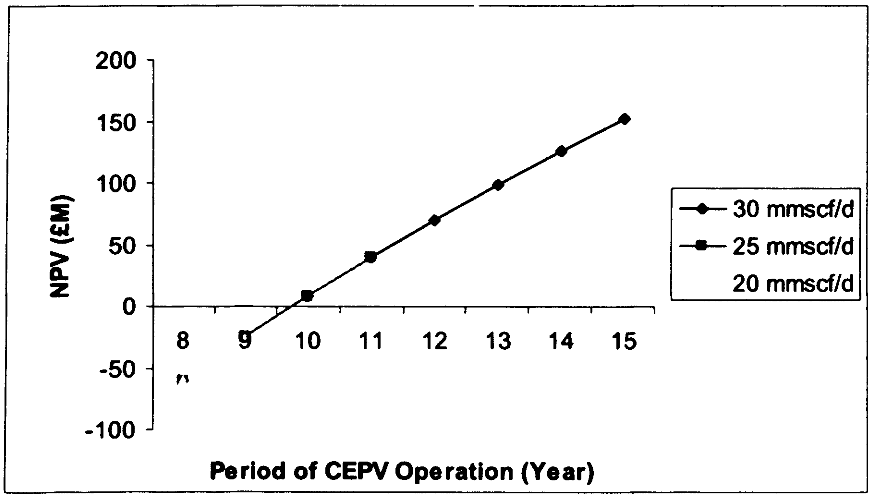


Figure 91 Effects of Changing Predicted Average Daily Gas Production and Length of Project upon NPV

Now consider Figure 90 and Figure 91 which show the effect upon IRR and NPV of changes in the predicted length of time the natural gas supply is available for different flow rates from the Clair Platform. The CEPV design has been optimised for a supply of natural gas at 20 mmscf/d from the Clair Platform for a period of 10 years supplemented by 3.1 bn m^3 from the Clair gas 'cap' obtained using the two new gas wells. If the natural gas supply from the Clair Platform was found to last beyond 10 years then the CEPV could theoretically continue to operate for a longer period. However the supplementary gas available from the Clair gas 'cap' is also important since when this runs out then there will be insufficient gas to maintain a sufficient supply to generate electricity economically. From the two graphs it can be seen that the IRR increases with both a longer period of CEPV operation and higher flow rates logarithmically so that a flow rate 30 mmscf/d lasting for 15 years from the Clair Platform produces an IRR of 9.46 % (Post Tax) and an NPV of £151.6 M.

In summary, the Clair Field Case Study appears to be economically viable provided that sufficient gas flows are continuously available for 10 years or more. The uncertainty of the gas flow rates from the Clair Platform and the gas reserve in the 'cap' is clearly a major area of risk for the investor. Ideally, the largest CEPV should be used to maximise returns but such a CEPV requires high CAPEX and consequently incurs greater risk. Certainly a subsidy is needed to overcome the additional costs of CO_2 sequestration to ensure economic viability.

7.3.2 Bonga Field

The Bonga Field is located offshore Nigeria 120 km south west of the Niger Delta. The field is in 1,245 m of water and covers an area of 60 km^2. The Bonga Field is a deepwater exploration which was awarded to a partnership of major oil companies by the Nigerian Government in 1993 and the first well was drilled in 1996[161]. Figure 92 shows the location of the Bonga Field, which has total recoverable reserves expected to be in excess of 600 million barrels of hydrocarbons. The development of the Bonga deepwater project has involved the design of a monohull 'Bonga FPSO' which is able to produce a maximum of 200,000 bbl of oil per day and 150 million cubic feet of gas per day using 16 oil producing and water injection wells[162]. The oil from the Bonga FPSO is stored onboard the FPSO prior to export via shuttle tankers. The natural gas can be piped via the Shell operated 268 km 32 inch Offshore Gas Gathering System to the Nigeria Liquefied Natural Gas Limited (NLNG) facilities at Bonny, Nigeria. Oil and LNG are exported to North America and Europe.

Nigeria LNG Limited was set up in 1995 on Bonny Island comprising of six LNG trains giving a total LNG production of 22 million tonnes and some 4 million tonnes of LPG per annum.

NLNG requires 3.5 bcf (99.1 million m^3) of feedgas per day at full production, which can be met by both onshore and offshore fields in the Niger Delta including the Bonga Field.

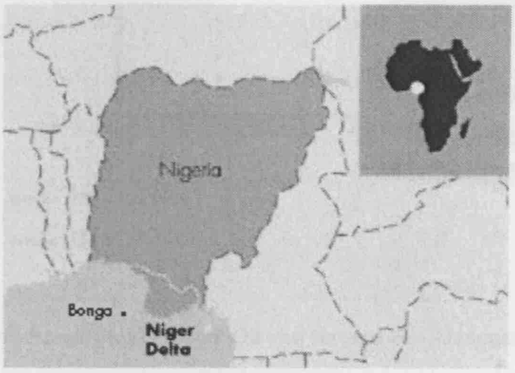


Figure 92 Location of the Bonga Field in Nigeria[163]

Concept

The concept explored here is for the CEPV to use the natural gas produced on the Bonga FPSO during oil recovery. Therefore, the Bonga FPSO will export natural gas to the CEPV; the CEPV will use the natural gas to generate electricity which is exported via subsea cable to Aladja to supply the growing electricity market in Nigeria; the CO_2 from the CEPV will be injected into another nearby field thereby affecting CO_2 sequestration. In the case where the CEPV needs to be shut down then the production on Bonga FPSO is uninterrupted because the gas system to the CEPV and Nigeria LNG is arranged in parallel. Figure 93 shows the existing oil and natural gas piping arrangements for the Bonga Field whilst Figure 94 shows the proposed concept whereby the CEPV imports natural gas and exports electricity to market and affects CO_2 sequestration.

Exporting electricity to Aladja in Nigeria has been chosen because it will allow the CEPV to connect to the Nigerian National Grid network. Aladja is connected by a 330 kV HVAC transmission infrastructure as seen in Figure 95.

Information provided by Shell and other sources164 was used by the Economic Model to examine the financial viability of using the CEPV in the Bonga Field. The key field information which differs from the Base Case CEPV scenario is given in Table 38.

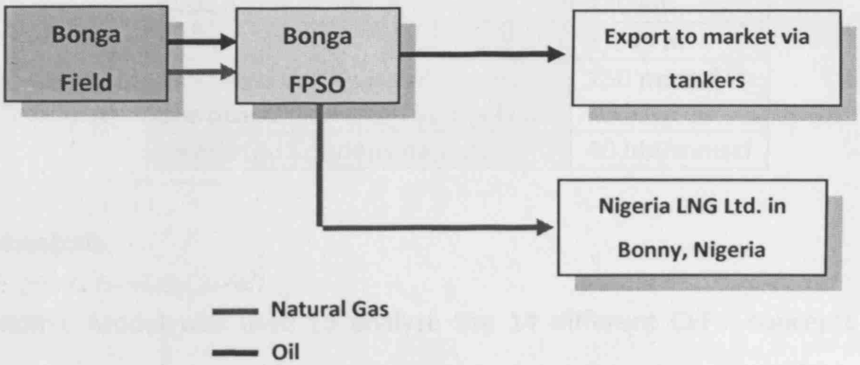


Figure 93 Bonga Field Present Oil and Natural Gas Arrangements

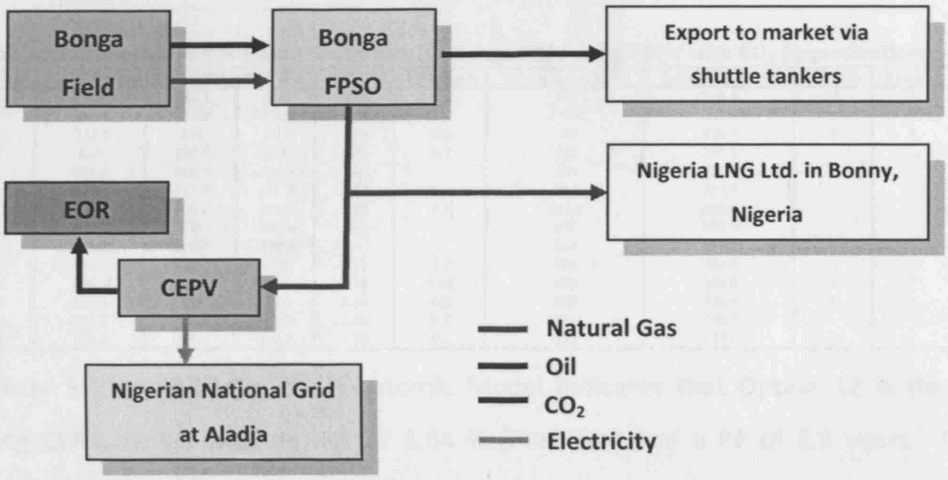


Figure 94 Bonga Field Proposed Oil and Natural Gas Arrangement When Using CEPV

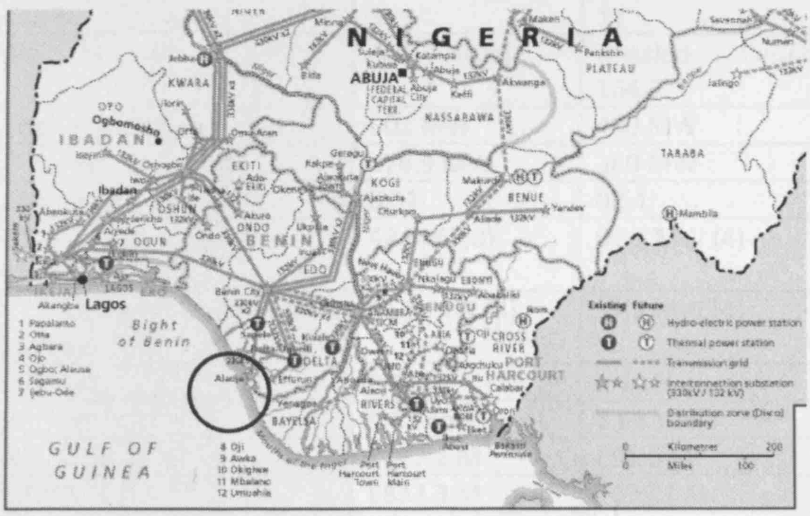


Figure 95 National Grid Network in Nigeria165

Table 38 Bonga Field Data

Distance to Shore	120 km
Water Depth	1,245 m
Averaged daily natural gas production from Bonga FPSO	150 mmscf/d
Predicted Condensate Ratio	40 bbl/mmscf

Analysis

The Economic Model was used to analyse the 14 different CEPV concepts to establish appropriate designs that would give acceptable economic performance. CO_2 sequestration must be considered in all cases and the results from the Economic Model are given in Table 39.

Table 39 Economic Performance Indicators for Bonga Field using CEPV with CO_2 Sequestration

Options	CAPEX (£M)	OPEX (£M)	NPV (£M)	IRR (%)	PP (Years)	Power Gen. (MW)	Power Exp. (MW)	Viability	Ranking
1	521	118.1	31.4	6.46	7.4	258	245.1	Y	3
2	601.3	132.8	-124.2	0.05	-	250.8	238.3		
3	934.2	210	30.7	5.79	7.6	502	476.9	Y	4
4	643	144.9	-112.5	0.57	9.7	279	265.1		
5	601.8	218.7	-158.3	-	-	264	250.8		
6	537.8	117.9	-31.7	3.51	8.4	267	253.7		
7	535.1	109.4	-79.2	1.25	9.3	263.2	250.0		
8	560.9	193	-288.6	-	-	157	149.2		
9	601.8	218.7	-158.3	-	-	264	250.8		
10	654.1	151	-5.5	4.77	7.9	328	311.6		
11	695.1	166.4	91.6	8.16	8.66	400	380.0	Y	2
12	833.3	203	127.1	8.64	6.8	502	476.9	Y	1
13	542.7	188.3	-48.4	2.74	8.7	259.5	246.5		
14	557.3	125.3	-71.5	1.76	9.1	258	245.1		

At electricity SSP of £38/MW, the Economic Model indicates that Option 12 is the best performing CEPV design with an IRR of 8.64 % (Post Tax) and a PP of 6.8 years. Other designs which are potentially economically feasible are Options 11, 1 and 3. Amongst all 14 scenarios only these four report a positive NPV.

Table 40 Technical Specifications and Financial Data for Two Best Performing CEPV Designs

Option	12	11
Manufacturer	ABB-Alstom	Ansaldo Cobra 164.3
Total Power Generated	502 MW	400 MW
Total Power Exported	476.9 MW	380 MW
Efficiency	0.52	0.54
GT Design Power and Number	42 MW (8)	66.5 MW (4)
ST Design Power and Number	41.5 MW (4)	37.5 MW (4)
IRR	8.64 %	8.16 %
PP	6.8 Years	8.66 Years
NPV	£127.1 M	£91.6 M
CAPEX	£833.3 M	£695.1 M
OPEX (First Year)	£203 M	£166.4 M

Now consider Table 40 which shows technical specifications and financial data for two best performing CEPV designs. It can be seen that Option 12, which is a 502 MW ABB-Alstom CCGT Plant that consists of eight gas turbines rated at 42 MW each and four steam turbines rated at 41.5 MW each, costs more than Option 11 with a CAPEX of £833.3 M (20 % more) but has a higher NPV (38 % more). With an IRR of 8.64 % (Post Tax) the PP is shorter than Option 11 by 1.9 years.

I-C-R is usually the preferred gas turbine type for continuous operation at maximum generating capacity. However, the Economic Model does not consider this criterion. Therefore, in this case study, the selection of preferred gas turbine option is solely based upon CAPEX, IRR and PP.

The CAPEX may appear to be significant but it has to be considered against the costs associated with installing LNG Plant. In the existing arrangement, as shown in Figure 93, the Bonga Field is presently supplying 4.28 % (4.24 million m^3) of NLNG's total requirement when at full production capacity. The NLNG plant currently consists of 5 LNG trains which have cost approximately USD 7.5 billion (£3.75 billion) i.e. around USD 1.5 billion for each train. Two further trains are planned, one to start up in 2008 and the other to start up in 2012, to cope with additional natural gas coming from new oil and gas reserves. In addition, specialist vessels are required to transport LNG to market.

The proposed CEPV arrangement (Option 12), as shown in Figure 94, exports 476.9 MW generated electricity (4 TWh per year). At full capacity, the CEPV imports 51.65 % (2.19 million m^3) of natural gas available from the Bonga Field per day. Whilst the CEPV is in operation the total natural gas exported to NLNG is 48.35 % (2.05 million m^3) of Bonga Field's daily production meaning a 2.2 % reduced supply to NLNG. It is reasonable to assume that this small reduction can be made up from supplies from other fields, either on or planned to come on stream, in the near future.

The cost of producing LNG is high because it involves liquefying the natural gas and then maintaining the LNG at low temperatures for export to Europe and North America. The proposed CEPV scenario with CO_2 sequestration needs electricity SSP of £30.21/MW to result in a zero NPV. Revenue beyond £30.21/MW is likely to be either met by subsidy from the government or higher electricity SSP in the region in order to result in a positive NPV. On the other hand, the cost of CO_2 sequestration is also high.

The Bonga Field Case Study appears to be economically viable simply because there are sufficient gas flows which are continuously available from the Bonga Field. The larger CEPV used in Bonga Field incurs higher CAPEX but this will be paid back by the returns from the revenue stream that has a high IRR.

7.4 Summary

In this chapter, sensitivity analyses have been undertaken using the Economic Model to examine the effect of changes in financial conditions and the CEPV technical specifications upon the economic viability of the CEPV concept. These have been achieved by making incremental changes to the Base Case CEPV described in the previous chapter. In addition, the effect of possible changes in the international financial conditions and in the CEPV's own financial arrangements has been examined.

IRR and PP are demonstrated to be affected negatively with an increasing Inflation Rate when the Interest Rate remains unchanged whilst the opposite occurs when Interest Rate increase with an unchanged Inflation Rate. The effect of changes to the Corporation Tax is important because Interest Rate payments can be offset against Corporation Tax and therefore this Gearing and NPV may be tuned to give the desired returns balanced against the financial risks taken. The influence of the US/UK currency exchange rate on the CEPV project is demonstrated to be significant especially when strong revenues from the sale of condensates are heavily relied upon. Electricity and Condensate Prices are shown to have a major impact upon the revenue stream of the CEPV.

The economic impact of making changes to the Base Case CEPV's technical specifications has also been examined by using the sensitivity analyses. These have been achieved by examining the economic viability of 14 CEPV scenarios with and without CO_2 sequestration as well as varying Base Case field characteristics.

Distance to Shore and Water Depth are shown to have a direct impact upon the costs of the CEPV where longer distances to shore across deep water translates into greater CAPEX and OPEX. From the results, it is clear that the IRR and PP are affected by relocating the CEPV particularly because of the lost revenue incurred during the move. It has been demonstrated that using CO_2 sequestration incurs significant additional cost which affects the economic viability of the CEPV unless there are tax advantages, CO_2 emission penalties applied to other 'polluting' power stations or financial subsidies to the CEPV for producing clean electricity.

From the analysis it can be seen that the selection process for the most suitable electricity generation plant will not depend solely upon IRR and PP because other factors will need to be carefully assessed for particular CEPV scenarios such as environmental operational aspects, risk, logistical and other financial issues. However, the results demonstrate that a large plant capable of generating significant quantities of electrical power giving rise to substantial revenue early in the project to offset the CAPEX is highly desirable.

The Clair Field in the west of Shetland Islands and the Bonga Field offshore Nigeria were examined as possible locations for the CEPV. The results from the Economic Model for this case study were examined in detail to assess economic viability. In the Bonga Field a further analysis has been undertaken to compare the economics of the CEPV concept with the alternative of piping the gas to shore to produce LNG.

The assessment of the Clair Field Case Study demonstrated that the uncertainty of the gas flows to the CEPV from the Clair Platform across the duration of the project and the unknown quantity of gas in the 'cap' presents a major area of risk for the investor. The largest CEPV maximised returns but requires greater CAPEX and therefore incurs greater risk. A financial subsidy or other financial instrument is needed to offset the additional costs of CO_2 sequestration.

The results from the Bonga Field Case Study demonstrate that the CEPV is economically viable simply because there are sufficient gas flows which are continuously available from the Bonga Field. In this case the larger CEPV is more attractive despite its incurring higher CAPEX because gas flows are more certain.

8 Conclusions and Further Work

8.1 Conclusions

The aim of this work has been to evaluate the technical and economic feasibility of exploiting remote area hydrocarbon reserves using a novel concept - The Clean Energy Producing Vessel (CEPV). The CEPV is a floating power station which generates electricity using natural gas that lies abandoned in many small or more distant offshore fields because a gas pipeline to shore is simply uneconomic. The CEPV exports the generated electricity to shore using a subsea electricity transmission cable to the National Grid. The exhaust emissions from the CEPV's electricity generating plant are processed and green house emissions are sequestrated into one of the many larger depleted oil and gas fields in the North Sea. Additional features of the CEPV include its ability to be moved from one field to another and its ability to reuse the same subsea transmission cable.

This thesis has investigated, reported and concluded the following key contributions associated with the CEPV concept beyond current understanding:

- It has investigated the novelty of the CEPV concept by reviewing published literature, the database of designs of ships, and by reviewing patents. No concept like the CEPV could be found in the literature search as reported in Chapter One and Chapter Two.
- It has investigated the current state of the UK electricity supply and demand picture and established a technical and economic case that justified further investigation into the CEPV concept. It was evident that the UK electricity generation industry needs to embark on a power station renewal programme in the near future and that new power station designs will need to be mindful of greenhouse emissions. The CEPV concept is one where significant amounts of energy can be generated with zero emissions with relatively low investment cost. This work was reported in Chapter One and Chapter Two.
- It has investigated the location, quality and quantity of stranded natural gas offshore together with exhausted wells. This was achieved by examining maps of the North Sea and offshore Nigeria to and gaining an understanding of typical likely locations for the CEPV. This work is reported in Chapter Two.

- The technologies needed for the CEPV were identified in Chapter Two. The technology areas were divided into the 'Gas Side' investigated in Chapter Three, the 'Electrical Side' investigated in Chapter Four and the 'Vessel Design' investigated in Chapter Five. These deeper investigations demonstrated the feasibility of the CEPV and highlighted key technologies that would need to be developed to ensure its implementation.
- Chapter Three considered the 'Gas Side' of the CEPV concept. This involved establishing an electricity generating plant with high thermal efficiency and specific power. The processing requirements for the natural gas were established and it was found that the 'raw' natural gas could not be burnt directly in the gas turbines because of impurities. The processing arrangements therefore included removing solids and condensates from the natural gas before it was fed to the gas turbines for combustion. The condensates were found to be valuable and would provide a further revenue stream. The exhaust gas was processed to remove the CO_2 which was fed to the CO_2 sequestration unit for pumping into disused oil and gas wells. In principle, the gas flow path was considered feasible. The electricity generating plant, natural gas processing plant and CO_2 sequestration plant was sized and cost to allow for further analysis in the CEPV design and Economic Model. Design evaluation matrix was also used to select the generation plant for the Base Case CEPV.
- Chapter Four considered the requirements and design of the CEPV's electrical generation and transmission system. Electrical generation of the CEPV is achieved using synchronous generators and a generated voltage of 25 kV was chosen because generators of this type are already in use in the electricity generating industry. Both HVDC transmission system and a HVAC transmission system have been proposed for the CEPV. HVDC transmission systems are more suited for distances beyond 80 km and will require a converter onboard the CEPV and an inverter ashore. Different types of transmission cable are proposed with the preferred HVDC option being the ICR cable. HVAC transmission is more suited for shorter transmission distances with the Trefoil cable arrangement being the preferred option. Also in this chapter it was identified that the 'riser' cable would be a dynamic cable and the analysis of a typical single core cable established a methodology for the calculation of cable stress and the assessment of the cable riser's fatigue life. The results of the analysis indicated

that such a cable could be designed and it was concluded through preliminary assessment of fatigue at using quasi-static analysis is that the cable fatigue life would exceed the CEPV's operational life.

- The conceptual design of the Base Case CEPV was established in Chapter Five. This was achieved by a total vessel design methodology by identifying the vessel type and the all the equipment required to be installed. Design evaluation matrix was used in deciding the Base Case CEPV and the selection of the vessel type. An FPSO was chosen as the base vessel because it is seen as a robust cost effective solution that offered minimal risk since these vessel types are already used extensively offshore in harsh weather conditions. The design of the layout of the Base Case CEPV was driven by volume to accommodate the gas processing plant, the electricity generating plant, the exhaust gas processing plant and the CO_2 sequestration plant. Furthermore, the CEPV design considered likely crewing levels and the crew's needs e.g. accommodation, stores and safety issues. In this chapter, the total cost of the Base Case CEPV has been calculated as UPC and TLC which are inputted into the Economic Model. The operational aspects of the CEPV were also considered with focus on importing of the Natural Gas and exporting of the CO_2 and electricity. It was concluded that the CEPV could indeed be built.
- In Chapter Six, the Economic Model has been built within Microsoft Excel and was designed such that it presents comparatively to standard economic models developed and used by oil and gas operators when evaluating the profitability of exploiting offshore gas reserves by pipeline. Verification and validation of the Economic Model has been carried out, as far as it was possible to do so, by comparing results with hand calculations, similar scenarios where available, and by acting on feedback provided by an economist within the oil and gas industry. The Base Case CEPV scenario was defined by using the Economic Model with CO_2 sequestration not selected for the Base Case to allow a more detailed investigation on the costs and revenues associated with using this technology. The commercial feasibility of the Base Case CEPV has been assessed using the Economic Model and the results seem to indicate that there is a reasonable financial return for the Base Case CEPV scenario despite the high initial investment. The Economic Model is considered a Novel Contribution to the analysis of electricity generation offshore.

- In Chapter Seven, the sensitivity analyses, undertaken using the Economic Model to examine the effect of changes in financial conditions and the CEPV technical specifications upon the economic viability of the CEPV concept, have been achieved by making incremental changes to the Base Case CEPV. The effect of possible changes in the international financial conditions and in the CEPV's own financial arrangements has also been examined. From the analysis it was shown that the selection process for the most suitable electricity generation plant will not depend solely upon IRR and PP because other factors will need to be carefully assessed for particular CEPV scenarios such as environmental operational aspects, risk, logistical and other financial issues. The results demonstrate that a large plant capable of generating significant quantities of electrical power giving rise to substantial revenue early in the project to offset the CAPEX is highly desirable. In this chapter, The Clair Field in the west of Shetland Islands and the Bonga Field offshore Nigeria were examined as possible locations for the CEPV. The assessment of the Clair Field Case Study has demonstrated that: The uncertainty of the gas flows and unknown quantity of gas reserve will present a major area of risk for the investor; larger CEPV may maximise returns but requires greater CAPEX and therefore incurs greater risk; and a financial subsidy or other financial instrument is needed to offset the additional costs of CO_2 sequestration. The results from the Bonga Field Case Study have demonstrated that the CEPV is economically viable when there are sufficient gas flows; and larger CEPV is more attractive despite higher CAPEX because gas flows are more certain.

These studies together represent an insight into the design and operation of a novel concept – The CEPV. This thesis has enabled the technical and economic feasibility of the CEPV to be investigated in a systematic approach.

The thesis is necessarily broad to cover all aspects of marine engineering requirements and is deep in those areas where novelty was identified such as the 'riser' cable, the CEPV design and the Economic Model. The design of the CEPV has presented a state-of-the-art solution to generate large amount of 'clean' electricity on demand on a 'mobile' power station.

The overall conclusion is that the CEPV is technically feasible, as the technologies are present and ready; and would be economically viable should an appropriate subsidy be awarded when generating 'clean' electricity.

The additional economic advantage is that the CEPV could be designed to fit into existing oil and gas operations, as proposed with the Clair Field, to provide clean energy and maintain 'oil lift' operations.

8.2 Further Work

The investigations documented in this thesis have raised further questions that require deeper and broader understanding of the various systems and influence on the design of the CEPV itself. In view of this, the author makes the following recommendations:

- That an improved gas flow model from wellhead to CO_2 sequestration plant is established to better an understanding of the specific requirements of the gas processing plant, prime-movers and sequestration of greenhouse gases. In particular, a better understanding of the geological sequestration issues should be added to the model to establish required injection pressures and leakage rates e.g. caprock integrity.
- A full computer based simulation of the CEPV should be developed to analyse accurately the operational aspects of the CEPV. This would be a useful tool to understand how all systems e.g. gas processing, combustion, electricity generation, transmission and CO_2 sequestration will work together in different scenarios including a dynamic situation.
- Investigations into Cable Riser performance indicate that there is potentially no issue with respect to failure of the cable riser through fatigue. However more detailed analysis is needed for each specific CEPV location since there is a wider range of operating conditions e.g. water depth, DP system performance, etc.
- A full CEPV design should be attempted with 3D modelling to better understand the integration of each plants and machinery with shipboard requirements. This could be achieved through using powerful ship design software known as Paramarine.

- Validation of the Economic Model proved to be very difficult because of a lack of data. Should appropriate data become available then the opportunity would exist for detailed Economic Model validation.
- Overall the author feels that the CEPV is a realistic solution to the difficult problem of generating clean electricity cheaply and is well worth further exploration.

References

1 World Energy Consumption, http://mmadan.wordpress.com/2006/08/23/worldwide-energy-consumption/ 23 Feb 2006.

2 Energy Data extracted from *Energy,* Department for Business Enterprise & Regulatory Reform (formerly known as DTi), HM Government.

3 *Energy White Paper, Our Energy Future – Creating a Low Carbon Economy,* Department of Trade and Industry, HM Government, United Kingdom, February 2003.

4 *Energy Statistics, - Electricity,* Department for Trade and Industry website, access date: 25 August 2006.

5 *Nuclear Fusion,* Atomic Archive, http://www.atomicarchive.com/Fusion/Fusion1.shtml, access date 3 August 2006.

6 *The Royal Commission on Environmental Pollution 22nd Report: Energy – The Changing Climate,* Royal Commission on Environmental Pollution, 2000.

7 *European Large Combustion Plant Directive (Directive 2001/80/EC),* The European Parliament, 2001.

8 *10 Year Life Extension at Dungeness B Nuclear Power Plant,* British Energy News, British Energy Website (www.british-energy.com), 15 Sept 2005.

9 *The Energy Challenge: Energy Review Report 2006,* Department of Trade and Industry, HM Government, United Kingdom, July 2006.

10 *Energy White Paper 2007 – Meeting the Energy Challenge,* BERR, HM Government, 2007.

[11] *Kyoto Protocol to the United Nations Framework Convention on Climate Change,* United Nations Framework Convention on Climate Change, HTML web version, http://unfccc.int/resource/docs/convkp/kpeng.html, as of 20 June 2008.

[12] P Cameron, *New Directions in UK Energy Policy,* International Journal of Energy Sector Management, Emerald Publishing Group, 2007.

[13] P Blackwood, *Oil & Gas UK – North Sea United!,* presentation for Oil and Gas UK in Aberdeen, http://www.ukooa.co.uk/new/features/pdfs/dbsummerbreakfast07.pdf, 5 June 2007.

[14] *Fluidised Bed Combustion,* World Coal Institute website www.worldcoal.org.

[15] *United Kingdom,* Country Analysis Briefs, Energy Information Administration, Official Energy Statistics from the US Government, http://www.eia.doe.gov/emeu/cabs/United_Kingdom/NaturalGas.html, as of 20 June 2008.

[16] *Meeting the Energy Challenge, The Energy White Paper,* Department of Trade and Industry, HM Government, May 2007.

[17] *The Role of Nuclear Power in a Low Carbon Economy, Paper 2: Reducing CO_2 Emissions – Nuclear and the Alternatives,* Sustainable Development Commission, March 2006.

[18] *Power Stations in the United Kingdom,* Statistics from Department of Trade and Industry, HM Government, United Kingdom, May 2006.

[19] *New Nuclear Plants Get Go Ahead,* BBC News, http://news.bbc.co.uk/2/hi/uk_news/politics/7179579.stm, 10 January 2008.

[20] *Nuclear Waste,* Course Note for Physics, City University New York, http://academic.brooklyn.cuny.edu/physics/sobel/Nucphys/waste.html.

[21] *Fusion as an Energy Source,* European Fusion Development Agreement, www.efda.org, as of 12 May 2007.

[22] European website on Decommissioning of Nuclear Installations, www.eu-decom.be, as of 16 June 2008.

[23] BWEA News, http://www.bwea.com/media/news/060327.html

[24] *Norfolk MPs Express Turbine Fears,* BBC News, http://news.bbc.co.uk/1/hi/england/norfolk/7361302.stm, 22 April 2008.

[25] *Regenesys Utility Scale Energy Storage, Network Performance Benefits of Energy Storage of a Large Wind Farm,* DTi, http://www.berr.gov.uk/files/file20402.pdf, as of 14 April 2007.

[26] *Offshore Wind: The Potential to Contribute a Quarter of UK Electricity by 2024,* Wind Engineering, Vol. 31, No. 2, Multi-Science Publishing Company, 2007.

[27] *The Renewables Obligation Order 2002,* Statutory Instrument 2002 No. 914, Office of Public Sector Information, HM Government, http://www.opsi.gov.uk/si/si2002/20020914.htm, as of 20 June 2007.

[28] *Survey of Energy Resources,* World Energy Council, 2006.

[29] A Frutiger, *Ecological Impacts of Hydroelectric Power Production on the River Ticino,* Part 2: Effects on the Larval Development of the Dominant Benthic Macroinvertebrate, Archiv fur Hydrobiologie Vol. 159 No 1, pp 57 -75, 22 January 2004.

[30] *RDA Sets New Timetable for Wave Hub,* South West of England Regional Development Agency, 2001.

[31] *Backing for Severn Barrage Power,* BBC Wales, http://news.bbc.co.uk/1/hi/wales/south_east/4927744.stm , as of 21 April 2008.

[32] P Eccleston, *Severn Barrage Gets 'Amber Light',* The Telegraph, 01 October 2007.

[33] *Harding Area Gas Project, North Sea, United Kingdom,* Industry Projects, Offshore Technology website, www. offshore-technology.com/projects/harding/, as of 15 May 2008.

[34] *FPSO and Modularised Process Equipment,* Global Process System, www.globalprocesssystem.com, as of 21 June 2008.

[35] *Gas Injection,* EnerMax Inc., www.enermaxinc.com/gas-injection, as of 16 June 2008.

[36] N Nikolaos, *Deep Water Offshore Wind Technologies,* MSc Thesis, University of Strathclyde, September 2004.

[37] *Power from Shore: ABB Technologies at Troll A Platform,* HVDC References, ABB website, www.abb.com, as of 12 June 2008.

[38] FPSO Figure, Abas Crane AS, www.abascrane.no, Access Date: 20 May 2008.

[39] Semi-submersible Figure, Atlantia Offshore Limited, www.atlantia.com/semisub/, Access date: 20 May 2008.

[40] I D Stewart, *Offshore Power Generation – Limited Life Expectancy,* Opportunities and Advances in International Power Generation, 18-20th March 1996. IEE, 1996.

[41] T Holt and E Lindeberg, *Gas Power With CO2 Deposition Locate on Abandoned Platforms,* Energy Conservation Management, Vol. 38, Suppl., pp. S247 – S252, 1997

[42] S Thomas and RA Dawe, *Review of Ways to Transport Natural Gas Energy from Countries which Do Not Need the Gas for Domestic Use,* Energy, 28 (2003) pp1461-1477, 2003.

[43] PJ Hill, B Inozu, T Wang, J J Bergeron, *Offshore Power Generation Using Natural Gas from Remote Deepwater Developments,* Offshore Technology Conference, 6-9 May 2002, Houston, Texas, USA, 2002.

[44] L Poldervaart, B Van Cann, H Wille, L D Rosen, *Floating Power Generation System,* United States Patent No. US7,119,460, B2, Date of Patent: 10 October 2006.

[45] *Forties – Grangemouth: The Failure of a Complex Tightly Coupled System,* The Oil Drum: Europe, www.theoildrum.com/node/3907, 27 April 2008.

[46] *CNG and Stranded Gas,* Projects and Initiatives, TransCanada, www.transcanada.com/company/CNG_stranded_gas.html, as of 20 June 2008.

[47] UKOOA Website, *http://www.ukooa.co.uk/education/storyofoil/geological-11.cfm,* 4 June 2007.

[48] P Lang, *Economic Future of North Sea Gas Fields,* Journal of Operational Research Society, Vol 41 No 2 pp 119 – 123, 1990.

[49] D Bricknell, *A New Generation of Naval Propulsion Systems,* Revue Defense Nationale, www.defnat.com, as of 20 June 2008.

[50] *World's Largest Cruise Ship – Powered and Propelled by ABB,* ABB United States, www.abb.us, 21 May 2007.

[51] O I Gilbertson, *Electric Cables for Power and Signal Transmission,* John Wiley & Sons Inc., United States of America, 2000.

[52] R J Bamford et al, *Application of the IACS Common Structural Rules for Oil Tankers to FPSOs,* Offshore Technology Conference 2007, Houston, Texas.

[53] A S Leyzerovich, *New Benchmarks for Steam Turbine Efficiency,* Power Engineering International, pepei.pennnet.com, as of 20 June 2008.

[54] P A Dellenback, *Improved Gas Turbine Efficiency Through Alternative Regenerator Configuration,* Journal of Engineering for Gas Turbines and Power, Vol 124 Issue 3 pp 441 – 446, 2002.

[55] T Korakianitis and DG Wilson, *Models for Predicting the Performance of Brayton-Cycle Engines,* Journal of Engineering for Gas Turbines and Power, ASME April 1994.

[56] *BGT's RB and KB Lines of Turbine Packages,* BGT Industrial, www.bgtgroup.com, as of 20 June 2008.

[57] *General Electric LM2500 Gas Turbine Photo,* Emcon Systems Machinery Troubleshooting, www.emcon-systems.com, as of 20 June 2008.

[58] T Korakianitis and KJ Beier, *Investigation of the Part-Load Performance of Two 1.12 MW Regenerative Marine Gas Turbines,* Transactions of the ASME, April 1994.

[59] Cheng Cycle Heat Recovery System, http://vganapathy.tripod.com/cheng.html (as of Oct. 30, 2006, 11:11 GMT).

[60] *Advanced Humid Air Turbine System,* http://www.pi.hitachi.co.jp/rd-eng/product/thermal-and-hydroelectric-sys/2010546_17257.html, Hitachi Ltd., Japan.

[61] Bathie WW, *Fundamentals of Gas Turbine,* 2nd Edition , Wiley, 1996.

[62] Wikipedia *Combined cycle,* http://en.wikipedia.org/wiki/Combined_cycle (as of Oct. 30, 2006, 11:15 GMT).

[63] E T Etuk, *Monohull Gas Processing and Electrical Power Generating Ship,* MSc Marine Engineering Ship Design Exercise, University College London, 2002

[64] *This Week in Science,* Science Mag, www.sciencemag.org/cgi/content/summary/311/5757/12n, as of 21 June 2008.

[65] *The Trent 60 Gas Turbine, For Power Generation and Mechanical Drives,* Rolls Royce plc.

[66] *RB211 Gas Turbines, For Oil and Gas Applications,* Rolls Royce plc.

[67] *Caledonio Oil and Gas Ltd Provision of Operations Support,* Ode, http://www.ode-ltd.co.uk/whatwedo/projectdata/caledonia.html, as of 12 June 2008.

[68] *Submerged Turret Production,* Advanced Production and Loading, www.apl.no, as of 12 June 2008.

[69] *Three-phase Separator,* Oilfield Glossary, Schlumberger, www.glossary.oilfield.slb.com, 2008.

[70] *Processing Natural Gas,* Naturalgas.org, 10 June 2008.

[71] *Amines,* Oilfield Glossary, Schlumberger, www.glossary.oilfield.slb.com, 2008.

[72] *Natural Gas Processing,* AP-42 Publication, United States Environmental Protection Agency.

[73] *Glycol Dehydrator,* Oilfield Glossary, Schlumberger, www.glossary.oilfield.slb.com, 2008.

[74] *Current Industry Perspective Gasification, Robust Growth Forecast, World Survey Results,* US Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory.

[75] *Oxy-Fuel Combustion Capture,* Scottish Centre for Carbon Storage, www.geos.ed.ac.uk/sccs, 2008.

[76] *Optimising CO2 Capture From Pulverised Coal Plants – Post-Combustion Capture with Amine Solvents,* Project Summary 357, Carbon Abatement Technologies Programme, DTi, 2005.

[77] *Progress in Post-Combustion CO_2 Capture,* European CO_2 Capture and Storage Conference Towards Zero Emission Power Plants, Knowledge for Business, 2005.

[78] *Progress in Post-Combustion CO_2 Capture,* European CO_2 Capture and Storage Conference Towards Zero Emission Power Plants, Knowledge for Business, 2005.

[79] *Post-Combustion Capture,* Scottish Centre for Carbon Storage, www.geos.ed.ac.uk/sccs, 2008.

[80] *Geologic Sequestration,* Climate Change – Greenhouse Gas Emissions, US Environmental Protection Agency, www.epa.gov, as of 20 June 2008.

[81] *The Technical Feasibility of Offshore Power Generation: Emission Management,* Chapman-Andrews, Department of Mechanical Engineering, University College London.

[82] *Carbon Dioxide Storage,* Scottish Centre for Carbon Storage, www.geos.ed.ac.uk/sccs, 2008.

[83] D C Thomas et al, *Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from the CO2 Capture Project,* Elsevier, 2005.

[84] *Ramgen's Unique CO_2 Compressor,* Ramgen Power Systems, www.ramgen.com, as of 20 June 2008.

[85] M Corcoran, *Abandonment of Offshore Oil and Gas Fields* OPL, 1997.

[86] H Martindale, E H Yap and R W G Bucknall, *Remote Area Hydrocarbon Exploitation Power Generation and Transmission,* JIP Phase One Reports, University College London, 2003.

[87] H Martindale, E H Yap, C-H Chien, and R W G Bucknall, *Remote Area Hydrocarbon Exploitation Power Generation and Transmission,* JIP Work Phase Two Reports, University College London, 2003.

[88] *Geologic Sequestration,* Climate Change – Greenhouse Gas Emissions, US Environmental Protection Agency, www.epa.gov, as of 20 June 2008.

[89] WD Gunter et al, *Large CO_2 Sinks: Their Role in the Mitigation of Greenhouse Gases from an International, National (Canadian) and provincial (Alberta) Perspective,* Applied Energy, 61 pp209 – 227, 1998.

[90] *Texas Unitization Fight Reopened with Proposed Legislation,* BNET United Kingdom, findarticles.com/p/articles/mi_qn4182/is_19970327/ai_n10103078, 27 March 1997.

[91] T Holt and E Lindeberg, *Gas Power With CO_2 Deposition Locate on Abandoned Platforms,* Energy Conservation Management, Vol. 38, Suppl., pp. S247 – S252, 1997

[92] WD Gunter et al, *Large CO_2 Sinks: Their Role in the Mitigation of Greenhouse Gases from an International, National (Canadian) and provincial (Alberta) Perspective,* Applied Energy, 61 pp209 – 227, 1998.

[93] *3167 LM5000STIG Gas Turbine Power Plant,* Pelrine & Buchanan's Maritime Trading Worldwide Ltd, www.generatorforsale.ca/turbines/gasturbines/50hz/3167.aspx, as of 21 June 2008.

[94] *FT8 Gas Turbine,* MAN Turbo, www.manturbo.com/en/500/500_productdetail.php?prod=gasturbineft8, as of 21 June 2008.

[95] *Wairakei Turbines and Generators,* New Zealand Geothermal Association, www.nzgeothermal.org.nz/geothermal_energy/education/turb-and-gen.asp, as of 21 June 2008.

[96] *Asynchronous (Induction) Generators,* Danish Wind Industry Association, www.windpower.org/en/tour/wtrb/async.htm, as of 21 June 2008.

[97] S Wekhande et al, *A Simple Wind Driven Self-Excited Induction Generator with Regulated Output Voltage,* Indian Institute of Technology Bombay.

[98] *Synchronous Generators,* Danish Wind Industry Association, www.windpower.org/en/tour/wtrb/syncgen.htm, as of 21 June 2008.

[99] I Tabatabaei et al, *Modelling and Simulation of a Salient-Pole Synchronous Generator with Dynamic Eccentricity Using Modified Winding Function Theory,* IEEE Transactions on Magnetics, Vol 40 No 3, May 2004.

[100] M A Rahman et al, *Super High Speed Electrical Machines – Summary,* Extended Summary for IEEE-PES Meeting at Denver 2004 – Panel Session on Super High Speeed Drive, 2004.

[101] K W Louie, *A Study on Magnetic Saturation Effects in a Synchronous Generator during Unbalanced Faults,* 2004 International Conference on Power System Technology, Singapore, November 2004.

[102] R E Joho, *Advances in Synchronous Machines: A Turbogenerator View,* IEEE Power Engineering Review, IEEE, 2002.

[103] F Shibata, *A Brushless and Exciterless, Self-Excited Three-Phase Synchronous Generator Having an Armature Winding Supplied with DC Exciting Current from a Voltage Current Transformer,* IEEE, 1989.

[104] S Nonaka and K Kesamaru, *Analysis of Voltage-Adjustable Brushless Synchronous Generator Without Exciter,* IEEE Transactions on Industry Applications, Vol 25 No 1, 1989.

[105] R W G Bucknall, *Lecture Notes for MSc Courses,* Department of Mechanical Engineering, University College London.

[106] *Electric Power Transmission,* Wikipedia, en.wikipedia.org/wiki/Electric_power_transmission, as of 21 June 2008.

[107] H D McGeorge, *Marine Electrical Equipment and Practice,* 2nd Ed, Butterworth-Heinemann, 1993.

[108] G O Watson, *Marine Electrical Practice,* 5th Ed, Butterworths, 1981.

[109] R C Nichols, *Plant Considerations for Offshore Generating Stations,* OCEANS '72.

[110] *Generator Main Circuit Breaker (GMCB),* Hitachi Asia, www.hitachi.sg/gmcb.shtml

[111] *North Sea Interconnector Would be the World's Longest,* Power Trading & Control Industry News, IET, 15 May 2003.

[112] *Limitation of Long Distance Transmission Cables for Offshore Wind Farms* , 2003, copyright produced by ESS Inc, consultants to Cap Wind Associates, LLC.

[113] C-H Chien, On the Steady-State Harmonic Performance of Subsea Power Cables Used in Offshore Power Generation Schemes, PhD Thesis, Department of Mechanical Engineering, University College London, 2007.

[114] *HVDC Light Converter Technology,* ABB, www.abb.com, as of 21 June 2008.

[115] *Offshore Wind Energy,* File 154089, BERR, HM Government.

116 PWM Technology for HVDC Light, The ABB Group, www.abb.com, as of 15 June 2008.

[117] Moyle Interconnector Nexans Cable, NI Energy Holdings, www.nienergyholdings.com, as of 15 June 2008.

[118] Cable Layers Confront the NorNed Challenge – Netherlands Offshore, Oil Online, www.oilonline.com, as of 15 June 2008.

[119] PT BICC BERCA Cables, BICC BERCA, www.biccberca.com, as of 15 June 2008.

[120] Submersible Cables, V. K. Polyshell Cables Pvt. Ltd., http://www.vkpolyshell.com/submersiblecables.htm, as of 15 June 2008.

[121] T Zachos, *Technical and Economical Evaluation of Power Transmission Options for Gas to Wire Project,* MSc Thesis, Department of Mechanical Engineering, University College London, 2003.

[122] Copper and Aluminium Prices, London Metal Exchange, www.lme.co.uk, as of 15 June 2008.

[123] *Skagerrak HVDC Interconnection,* ABB website, www.abb.com, as of 21 June 2008.

[124] F Baradaran-Seyed, *On the Dynamics of Flexible Risers and Suspended Pipe Spans,* PhD Thesis, Department of Mechanical Engineering, University College London.

[125] G Moe and O Arnsten, An Analytical Model for Static Analysis of Catenary Risers, Proceedings of the Eleventh International Offshore and Polar Engineering Conference, Trondhein, Norway, Vol. 2, pp 248 – 253.

[126] *Working Time Regulation – Offshore Work,*International Association of Drilling Contractors, www.iadc.org, as of 20 June 2008.

[127] *Tension Leg Platform (TLP),* Global Security, www.globalsecurity.org/military/systems/ship/platform-tension-leg.htm, as of 21 June 2008.

[128] *Representative Projects,* Ultramarine website, www.ultramarine.com/g_info/moses/projects.htm, as of 16 June 2008.

[129] *Gulf of Alaska Exploration Wells,* Minerals Management Service, US Government, www.mms.gov/alaska/fo/wellhistory/goawells.htm, as of 21 June 2008.

[130] *Aker Kvaener to Deliver Pusnes Mooring Equipment to Gjoa Semisubmersible Platform,* Press Release, Aker Solutions, www.akersolutions.com, 2 May 2007.

[131] *Exxoteq Pronosis,* Exxoteq website, demos.portfolios.in/exxoteq/prognosis.htm, as of 16 June 2008.

[132] *Floating Production Storage and Offloading,* Wikipedia, en.wikipedia.org/wiki/Floating_oil_production_system, as of 21 June 2008.

[133] *FPSO's, Floaters & Jack Ups,* Toolpusher website, www.toolpusher.co.uk/Rigpics/fpso-floaters.htm, as of 16 June 2008.

[134] *FPSO Installations,* Oil & Gas Safety, www.fs-oilgas.com, as of 17 June 2008.

[135] J Macgregor et al, *Design and Construction of the FPSO vessel for the Schiehallion Field,* Transaction of RINA, 1999, London

[136] Mr. Andrew Clayson, Managing Director, APL UK Ltd., 20 June 2008.

[137] Rolls Royce Trent Gas Turbine, http://www.rolls-royce.com/energy/products/powergen/trent/default.jsp, as of 20 August 2008.

[138] D G M Watson, *Practical Ship Design*, Elsevier, 1998.

[139] *Phase One Economic Model Report*, BG Group, BP and Shell Joint Industry Project, Department of Mechanical Engineering, University College London, 2003.

[140] Bank of England website, www.bankofengland.co.uk. access date: 15 January 2008.

[141] www.scotland.gov.uk/Resource/Img133186/0041384.gif

[142] *Financial Gearing Definition,* London South East, http://www.lse.co.uk/financeglossary, as of 21 June 2008.

[143] *Corporate Tax Rates,* HM Revenue & Customs, HM Government, www.hmrc.gov.uk/ctsa/ct_rate_band.htm, as of 6 April 2008.

[144] *Q & A: Europe's Carbon Trading Scheme,* BBC News, news.bbc.co.uk/1/hi/sci/tech/4114921.stm, 20 December 2006.

[145] *Electricity Wholesale Price,* OFGEM, www.ofgem.gov.uk, as of 2 November 2007.

[146] *Oil Price,* OFGEM, www.ofgem.gov.uk, as of 2 November 2007.

[147] *British Pound Currency Exchange Forecast,* The Financial Forecast Center, forecasts.org/exchange-rate/british-pound-exchange-rate.htm, as of 3 November 2007.

[148] *XE.com Conversion, http://www.xe.com,* as of 02 Sept 2008.

[149] *Clair Field,* Offshore Technology, www.offshore-technology.com/projects/clair, as of 8 January 2008.

[150] National Grid, "The Statement of Connection Charging Methodology", April 2003.

[151] *Cogeneration Combined Cycle,* World of Renewables, www.worldofrenewables.com/page.php?pageid=11, as of 21 June 2008.

[152] *Inflation Rate and Interest Rate,* Scottish Government, www.scotland.gov.uk/Resource/Img133186/0041384.gif, as of 18 January 2008.

[153] *Corporation Tax Rates,* http://www.hmrc.gov.uk/ctsa/ct_rate_band.htm, as of 2 Sept 2008.

[154] *British Energy Trading and Transmission Arrangements (BETTA),* BERR, HM Government, as of 21 June 2008.

[155] *Crude Oil Price Forcast,* www.oil-price.net as of 2 Sept 2008.

[156] *Energy Price,* Bloomberg.com, www.bloomberg.com/energy, as of 21 June 2008.

[157] *High Oil Prices Hit Global Economies,* BBC News, news.bbc.co.uk/1/hi/business/7421778.stm, 28 May 2008.

[158] The Clair Reservior, BP Asset Portfolio, BP, as of 12 March 2008.

[159] *Clair Field,* Projects, Rigzone, www.rigzone.com/data/projects/project_detail.asp?project_id=123, as of 12 March 2008.

[160] *Dounreay Site Restoration Ltd.,* www.dounreay.com, as of 12 April 2008.

[161] *Bonga Deepwater Project, Niger Delta, Nigeria*, www.offshore-technology.com.

[162] *Shell's Bonga Field Starts Up Offshore Nigeria*, www.shell.com, 28/11/2005.

[163] *Bonga Deepwater Project, Niger Delta, Nigeria,* Shell Website, http://www.shell.com/home/content/eandp-en/major_projects/bonga_project/major_project_bonga_190805.html, as of 12 March 2008.

[164] *Bonga Field*, Rigzone, www.rigzone.com, as of 12 March 2008.

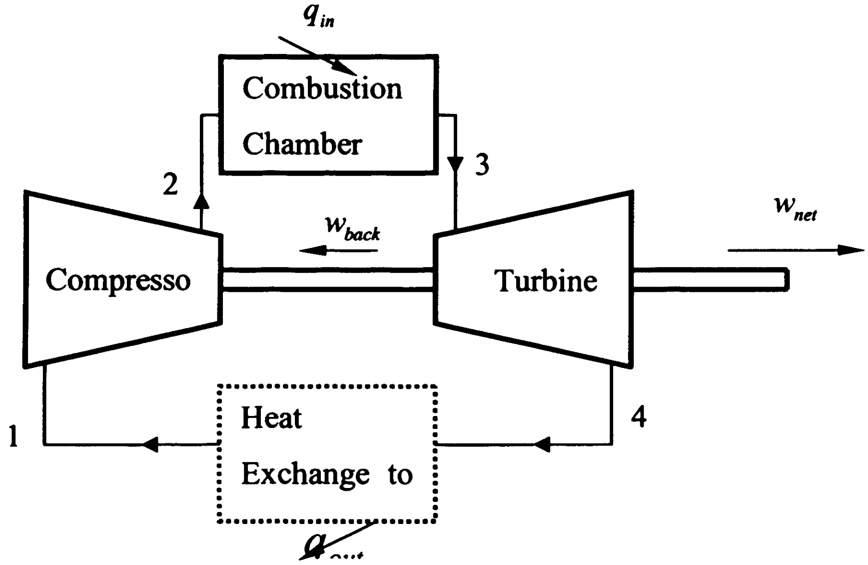
[165] *Nigerian National Grid Network,* Global Energy Network Institute, www.geni.org, as of 12 April 2008.

Appendix 1

Gas Turbine Cycles

Brayton Cycle

The Brayton Cycle is the ideal cycle for gas turbines. Although gas turbine operation is an open cycle, the closed loop Brayton cycle can model this open cycle by including a heat addition process from an external source and a heat rejection process to the ambient air. The simplest form of the Brayton Cycle is as follows (Figure 1).



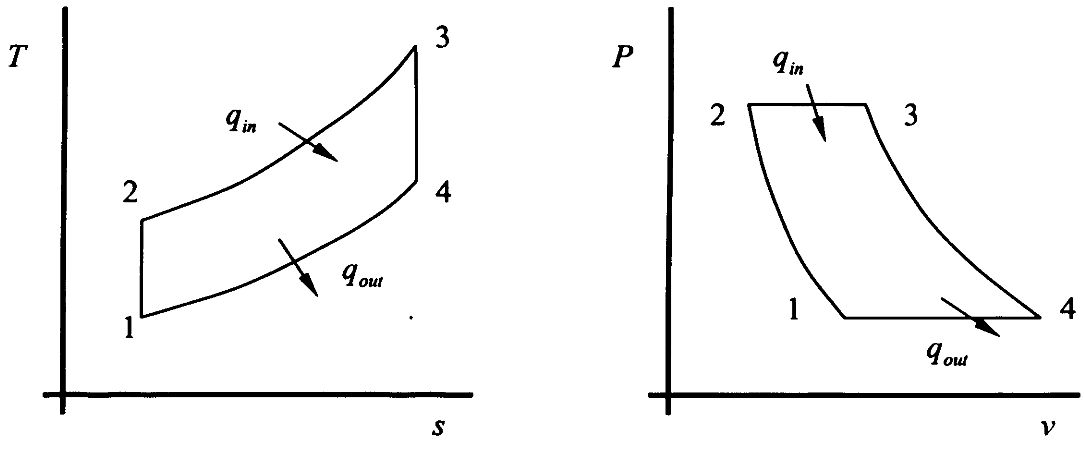


Figure 1Brayton Cycle representation of a gas turbine, and *T-s P-v* plots of the ideal cycle.

The ideal process consists of four internally reversible processes which are isentropic compression (1-2), constant pressure heat addition (2-3), isentropic expansion (3-4) and constant pressure heat rejection (4-1). Therefore

$s_2 = s_1$, $s_4 = s_3$, $P_1 = P_4$ and $P_3 = P_2$.

The steady flow energy equation, when applied first to the compressor and then to the turbine, while ignoring kinetic and potential energy changes, gives

$$q_{in} = q_{23} = h_3 - h_2 = C_p(T_3 - T_2)$$

$$q_{out} = -q_{41} = h_4 - h_1 = C_p(T_4 - T_1)$$

The thermal efficiency of the Brayton cycle can now be expressed as

$$\eta_{th} = \frac{w_{net}}{q_{in}} = 1 - \frac{q_{out}}{q_{in}} = 1 - \frac{(T_4 - T_1)}{(T_3 - T_2)} = 1 - \frac{T_4(1 - T_1/T_4)}{T_3(1 - T_2/T_3)} = 1 - \frac{1}{r_p^{(k-1)/k}}$$

This follows from the isentropic relations for ideal gases and the *s* and *P* relations above :-

$$\frac{T_2}{T_1} = \left(\frac{P_2}{P_1}\right)^{(k-1)/k} = \left(\frac{P_3}{P_4}\right)^{(k-1)/k} = \frac{T_3}{T_4}, \qquad r_p = \frac{P_2}{P_1} = \frac{P_3}{P_4}$$

r_p is the pressure ratio and *k* is the ratio of specific heats C_p/C_v.

As can be seen the efficiency increases with pressure ratio. The pressure ratio is limited by the maximum temperature sustainable by the turbine blades which sets the top temperature (T_3) of the cycle. The bottom temperature (T_1) is also set by the ambient air temperature, hence the cycle has to fit between these two limits. Figure 2 shows that optimisation of the cycle depends on a balance between an acceptable thermal efficiency and a sufficient net work output.

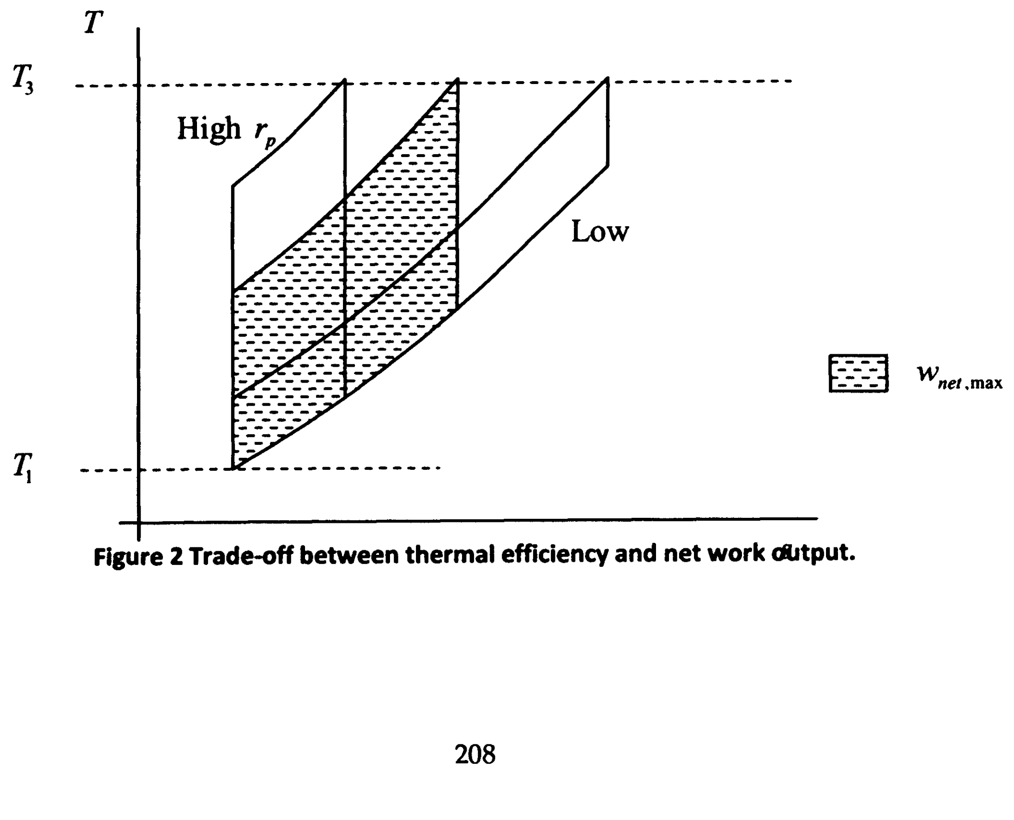


Figure 2 Trade-off between thermal efficiency and net work output.

Actual Cycle

Typical pressure ratios for gas turbine engines vary between 5 and 35, and T_3 can be as high as 1698 K if the turbine blades are ceramic-coated and cooled.

The actual cycle will differ from the ideal cycle due to some pressure drop in the 'constant pressure' heat addition and rejection processes and also due to irreversibilities in the compressor and turbine. As a result the actual cycle will deviate from the ideal as shown in figure 3. The compressor and turbine deviations can be accounted for by consideration of their adiabatic efficiencies and hence the relation between actual enthalpy change and ideal enthalpy change.

Compressor efficiency $$\frac{w_{isentropic}}{w_{actual}} = \frac{h_{2\,isentropic} - h_1}{h_{2\,actual} - h_1}$$

Turbine efficiency $$\frac{w_{isentropic}}{w_{actual}} = \frac{h_3 - h_{4\,actual}}{h_3 - h_{4\,isentropic}}$$

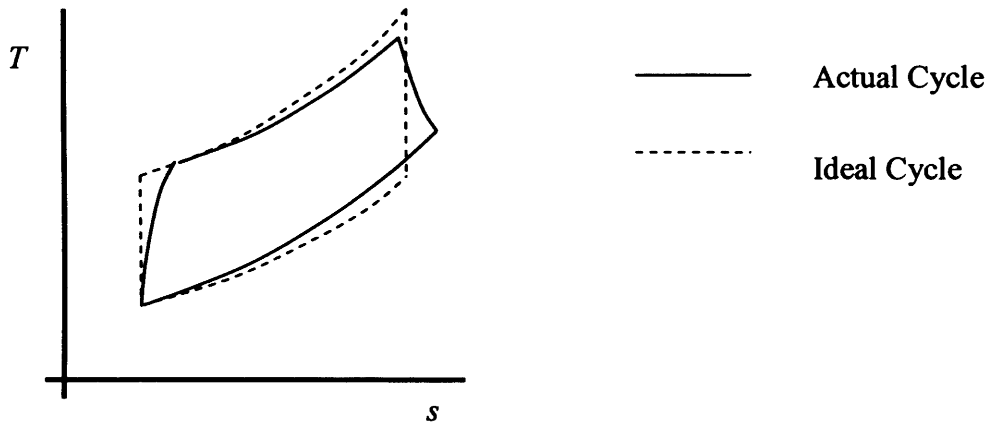


Figure 3 Actual cycle deviation from the ideal Brayton cycle.

Ideal cycle analysis is better if carried out while taking into account changes in fluid specific heats with temperature.

$$ds = \frac{du}{T} + \frac{Pdv}{T} = C_p \frac{dT}{T} + R\frac{dv}{v}$$

$$s_2 - s_1 = \int_1^2 C_p(T)\frac{dT}{T} - R\ln\frac{P_2}{P_1}$$

If we define s^0 by $s_{T_1}^0 = \int_0^{T_1} C_p(T)\frac{dT}{T}$, then for an isentropic process

$$0 = s_2^0 - s_1^0 - R\ln\frac{P_2}{P_1}$$

$$\frac{P_2}{P_1} = \frac{e^{s_2^0/R}}{e^{s_1^0/R}}$$

The exponential $e^{s^0/R}$ is known as the relative pressure *Pr* and is tabulated for use in this expression, that is

$$\left(\frac{P_2}{P_1}\right)_{s=\text{constant}} = \frac{\mathrm{Pr}_2}{\mathrm{Pr}_1}$$

Brayton Cycle with Recuperation

Where the temperature difference is sufficient, a recuperator (regenerator) can be included to transfer some of the heat from the exhaust gases leaving the turbine to the compressed air leaving the compressor, hence lowering the fuel input required to raise the temperature in the heat addition process (figure 4).

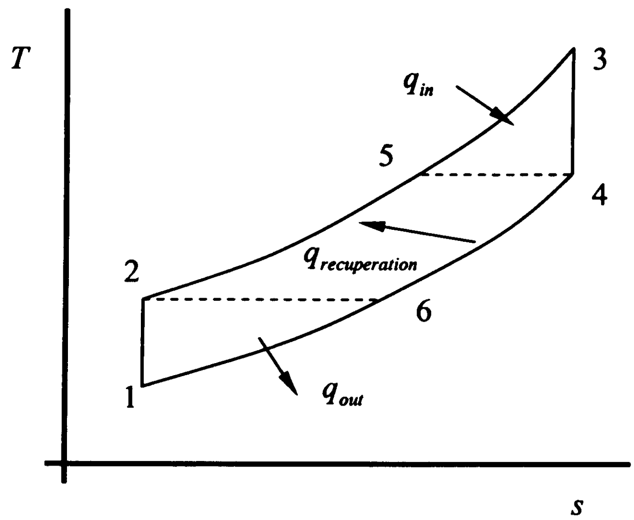


Figure 4 *T-s* Diagram for a Brayton cycle with recuperation

The effectiveness of the recuperator is usually about 0.7 for reasons of size and cost, hence T_5 will be lower than T_4. In the ideal case with $T_5 = T_4$, thermal efficiency is

$$h_{th} = 1 - \frac{q_{out}}{q_{in}} = 1 - \frac{T_2 - T_1}{T_3 - T_4} = 1 - \frac{T_1(T_2/T_1 - 1)}{T_4(T_3/T_4 - 1)} = 1 - \frac{T_1}{T_3}\frac{T_3}{T_4} = 1 - \frac{T_1}{T_3}(r_p)^{(k-1)/k}$$

As is already clear from figure 5 regeneration is most effective at low pressure ratios and low minimum to maximum temperature ratios.

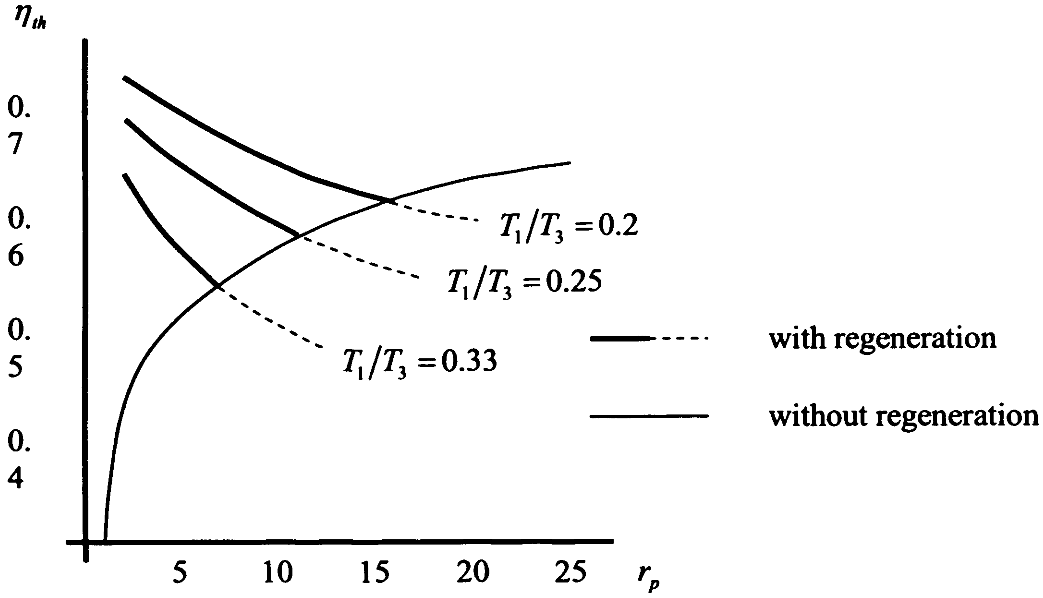


Figure 5 Effect of regeneration (100% effectiveness) on Brayton cycle thermal efficiency.

Intercooling and Reheating

Cooling of the working fluid during compression means that less work is required to complete this process. This is because the maximum specific volume of the fluid during compression is reduced. As shown in figure 6 the process approaches an isothermal path. More than two stages is generally not attempted however due to a drop in incremental improvement in work done.

Examination of the work done during a two stage compression process shows that this is minimised when the pressure ratios across each stage are the same.

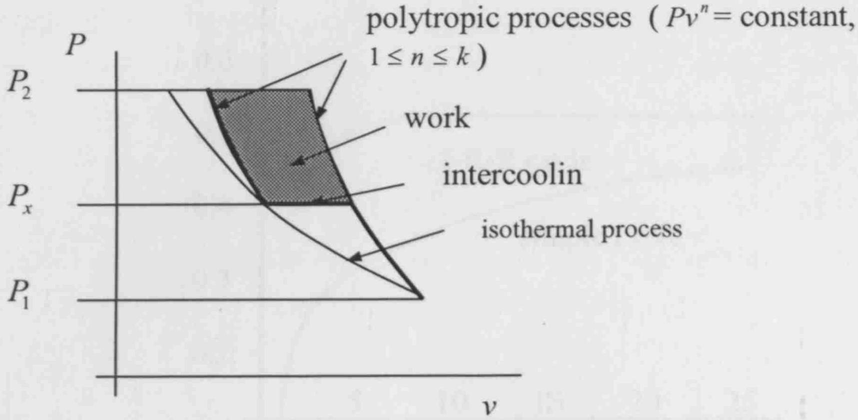


Figure 6 Work saved by two stage compression.

By exactly the same argument, reheating during expansion improves the work output during the process. Note however that this improved net work output will be at the expense of thermal efficiency as more heat needs to be applied during the expansion process. Only when recuperation is included can the full effects of intercooling and reheating be realised - extra stages of intercooling and reheating would in fact make the compression and expansion processes more and more like the isothermal processes of the Ericsson cycle leading to a thermal efficiency the same as that of the ideal Carnot cycle.

$$h_{th,\,Carnot} = 1 - \frac{T_1}{T_3}$$

Applying intercooling, reheating and recuperation to the ideal Brayton cycle leads to figure 7 (Complex cycle, see also figure 8) where for optimum operation

$$\frac{P_2}{P_1} = \frac{P_4}{P_3} \text{ and } \frac{P_6}{P_7} = \frac{P_8}{P_9}$$

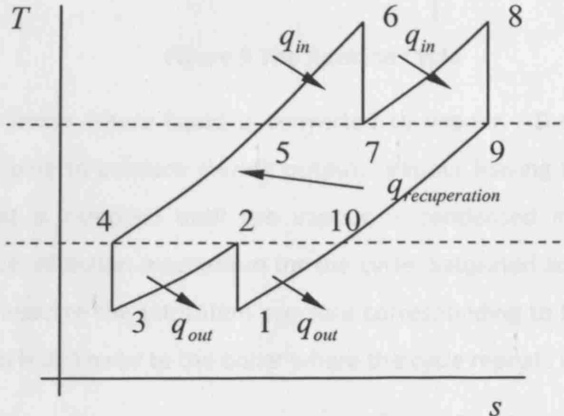


Figure 7 Ideal gas turbine cycle with intercooling, reheating and recuperation.

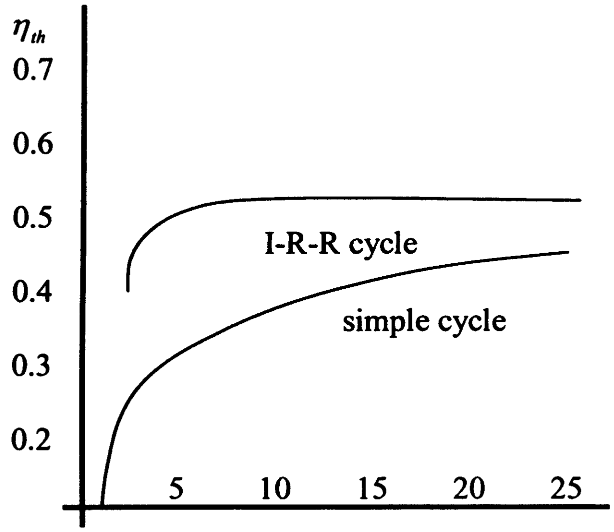


Figure 8 Effect of intercooling, reheating and recuperation on cycle efficiency and its variation with pressure ratio. (T_1=288K, T_6=1400K, compressor, turbine and recuperator efficiencies 87%, 89% and 80% respectively.)

Rankine Cycle

A steam engine operating on the Rankine cycle 12341 is shown in figure 9 below. The plant itself will comprise a boiler (or heat exchanger), a turbine, a condenser and a boiler feed pump (compressor).

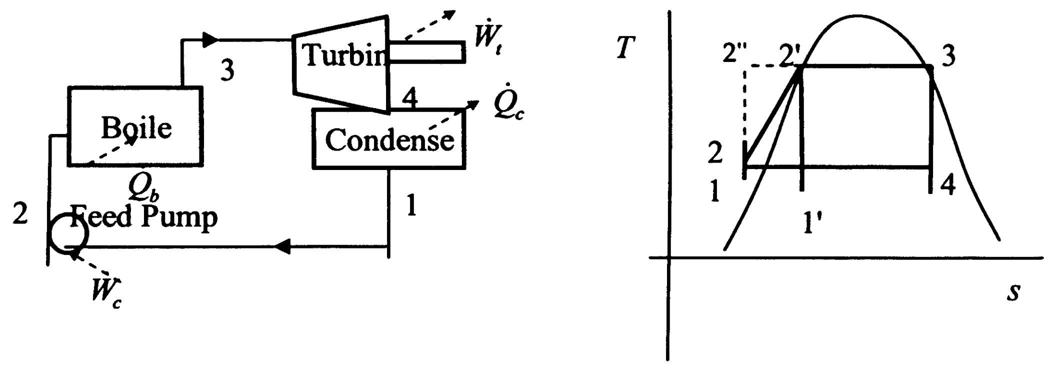


Figure 9 The Rankine Cycle

Heat is supplied to a boiler where liquid is converted to vapour. The vapour is then expanded adiabatically in the turbine to produce a work output. Vapour leaving the turbine then enters the condenser where heat is removed until the vapour is condensed into the liquid state. The condensation is the heat rejection mechanism for the cycle. Saturated liquid is delivered to a plump where its pressure is raised to the saturation pressure corresponding to the boiler temperature, and the high-pressure liquid is delivered to the boiler where the cycle repeats itself.

The Rankine cycle is reversible but its efficiency is lower than that of the Carnot cycle operating between the same temperature limits T_1 and T_3. The Carnot cycle for these limits is also shown on the T-s (temperature-entropy) plane in figure A.9 and is the cycle 1'2'341'. (For given temperature limits, the thermal efficiency of the Carnot cycle is the maximum obtainable). The basic Rankine cycle differs from the Carnot cycle in that the heat-addition process does not occur at constant temperature. The average temperature at which the heat is added is less than T_3 because part of the process involves heating the compressed liquid up to the saturation temperature at the high pressure. If it were possible to operate the cycle as 12"341, a Carnot cycle would be obtained exactly; however process 1-2" would involve liquid compressions to enormous pressure.

Rankine cycle efficiency

Since the Rankine cycle is reversible its efficiency may be written in the form

$$\eta_{cy} = 1 - \frac{T_1(s_4 - s_1)}{\int_2^3 Tds} = 1 - \frac{T_1(s_4 - s_1)}{T_m(s_3 - s_2)} = 1 - \frac{T_1}{T_m}$$

where T_m =Tds/(s_3-s_2), and is called the mean temperature of heat reception.

Cycle efficiency can be increased by lowering T_1 and raising T_m. T_1 is limited by the condenser cooling water temperature and the economic size of the condenser. Depending on other parameters of the cycle, a reduction in condenser pressure from 0.1 bar (T_1 = 45.8°C) to 0.05 bar (T_1 = 32.9°C) will give an increase in efficiency of 1% to 2% but the volume of steam entering the condenser will almost double.

An increase in T_m can be achieved by continuing the constant pressure heating process in the boiler beyond the saturated vapour point. This gives the cycle shown in figure 10 for which T_m is evidently higher than for the basic non-superheat cycle between the same pressure limits.

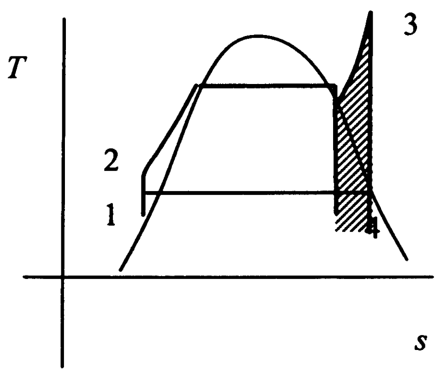


Figure 10 Superheated Rankine Cycle

As well as increasing the cycle efficiency and reducing specific steam consumption (s.s.c. is defined as the steam flow in kg/h required to develop 1 kW), superheating has other advantages. It increases the specific work output by an amount proportional to the shaded area in the sketch and it increases the exhaust dryness fraction. The latter advantage is important. A dryness fraction less than about 0.9 gives rise to serious erosion problems in the turbine blading, and expansion of initially dry saturated steam from quite low pressure to a moderate vacuum will readily give a dryness fraction less than 0.9 if the expansion is typically efficient.

For example, the isentropic expansion of dry saturated steam at 20 bar to a pressure of 0.05 bar results in a dryness fraction of 0.74. The minimum practicable exhaust pressure is about 0.04 bar and a dryness fraction of 0.9 will result from isentropic expansion of dry saturated steam from an initial pressure of only 0.4 bar. For reasons given below it is desirable that boiler pressures should be very much greater than 20 bar unless the power output is quite small. Superheating is altogether an attractive means of improving cycle efficiency but there is a practical limit on T_3 which is fixed by the materials subjected to this temperature. The limit at present for T_3 is about 565°C, higher than which expensive austenitic steels are required. Calculations indicate that there is still much to be gained by improving high-temperature materials.

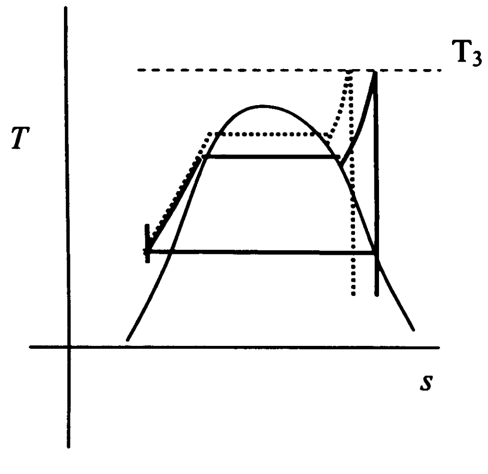


Figure 11 Higher Pressure Rankine Cycle

With T_3 fixed an increase in T_m and hence a higher cycle efficiency can be obtained by increasing the boiler pressure. This is evident from figure 11 above. It is also clear from the sketch that increasing the boiler pressure has little effect on the specific work. However it does reduce the exhaust dryness fraction - this is undesirable (the remedy lies in the use of a reheat cycle; see next section). In addition the increased boiler pressure and hence increased density of the steam entering the turbine results in smaller turbine blades and this can have an adverse effect on the turbine isentropic efficiency. The potential benefit of increased boiler pressure in the actual power plant will be lost if the high pressure turbine blading is already rather small. The optimum pressure for the largest power turbines today is 160 bar.

Rankine Cycle with Reheat

Even superheating the steam to the maximum permissible temperature would not, in many cases, permit the boiler pressure to be increased to the limit imposed by the high pressure turbine blading, because the exhaust dryness fraction would still be unacceptable. It is possible, however, to reap the advantage of high boiler pressure without excessive moisture in the exhaust if the process known as reheating is introduced into the cycle (figure 12). In this process the steam is expanded in the first turbine stage and is removed from the turbine at some suitable pressure higher than the condenser pressure and is returned to the boiler where its temperature is raised at constant pressure to a value near or equal to that at entry to the HP turbine. The reheated steam is then returned to the turbine to complete its expansion to condenser pressure.

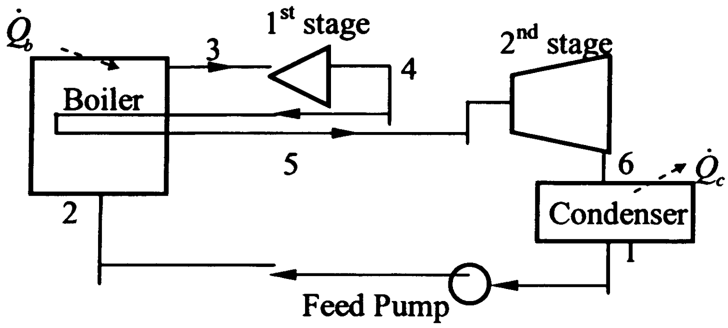


Figure 12 Reheat Cycle

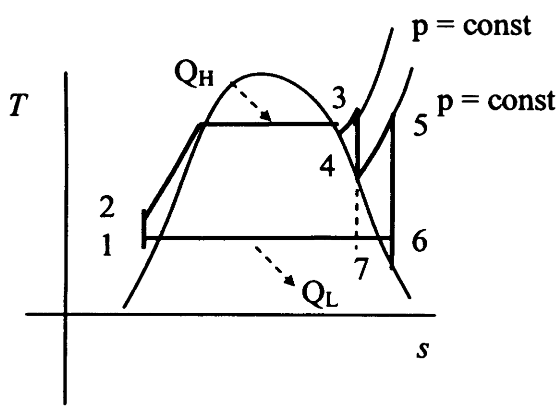


Figure 13 Reheat Cycle

As far as exhaust wetness is concerned it will normally be sufficient to have a single stage of reheat as has just been described. This is the normal British practice in power station plant.

An important secondary attraction of reheat is that it can increase T_m and hence increase the efficiency of the cycle. This is evident from the sketch above (figure 13). If the reheat pressure p_4 is sufficiently high then the mean temperature of heat reception between 4 and 5 will be higher than T_m

for the cycle without reheat. It follows that T_m for the reheat cycle 1234561 is then higher than for the non-reheat cycle 123471. Conversely, too low a reheat pressure will result in a lower efficiency due to the inclusion of reheat. It may be inferred that there is a particular reheat pressure for maximum efficiency and that this pressure is not the boiler pressure, for, obviously, the reheat effect vanishes as p_4 approaches p_3. A simple general expression for the value of p_4 that will give the maximum value for η_{cy} is not available but in practice p_4 is approximately equal to $\frac{1}{4}$ to $\frac{1}{5}$ of p_3 and for typical cycles the gain in η_{cy} will be about 2% or 3%.

Note that reheating increases the specific work of the cycle but at the expense of providing the pipework for the steam's return journey from the turbine to the boiler and practically inevitable irreversibilities resulting from the process. It is for this reason that it is seldom found to be economically worthwhile to have more than one stage of reheat. (in a reversible cycle a large number of reheat stages would improve the efficiency more than would a single stage. For, keeping point 6 in the two-phase region - if point 6 moves out of the wet region the mean temperature of heat rejection will rise - a sufficiently large number of reheat stages will cause the state of the steam to follow an approximately straight horizontal line between 3 and 5 and consequently will increase T_m and therefore increase η_{cy}).

The methods just described for increasing T_m have been mainly concerned with the steam side of the cycle. T_m can also be increased by raising the temperature at which the liquid enters the boiler. The process involved is called feed heating.

Rankine Cycle with Feed Heating (Regenerative Feed Heating)

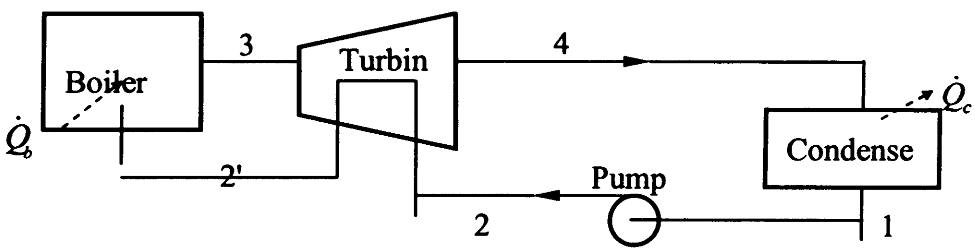
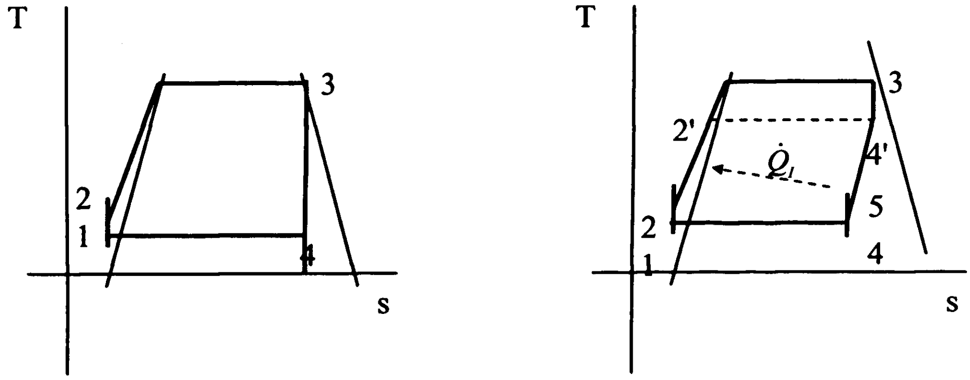


Figure 14 Feed Heating Cycle (i)



(a) (b)

Figure 15 Feed Heating Reversibility (i)

Consider the non-superheat, non-reheat Rankine cycle 12341 sketched at (a) above (figure 15, see also figure 14). If instead of pumping the water into the boiler at state 2 it is passed through passages in the turbine casing so that its temperature is raised by heat transfer with the expanding steam in the turbine it will then enter the boiler requiring a smaller temperature rise than in the simple cycle. T_m is therefore increased.

Now, the heat transfer process in the turbine could, in principle, be made reversible by arranging that the feed water in the passages was always only infinitesimally lower in temperature than the steam just outside (this can be achieved by passing the feed water coming from the condenser through an infinite number of coils, the coils being placed between successive pairs of an infinite number of turbine stages). The complete cycle would then be reversible and would appear as shown in sketch (b) above (figure A.15). The reversibility means that for each unit of heat transfer in the turbine at a temperature T, the entropy increase in the feed water must be balanced by an equal entropy decrease in the steam so that the lines 22' and 54' are parallel. Therefore $s_{4'} - s_{2'} = s_4 - s_1$. The efficiency of the cycle is

$$\eta_{cy} = 1 - \frac{(h_4 - h_1)}{(h_1 - h_2)} = 1 - \frac{T_4(s_4 - s_1)}{T_m(s_3 - s_2)} = 1 - \frac{T_L}{T_m}$$

and T_m and therefore η_{cy} are higher than for the original cycle.

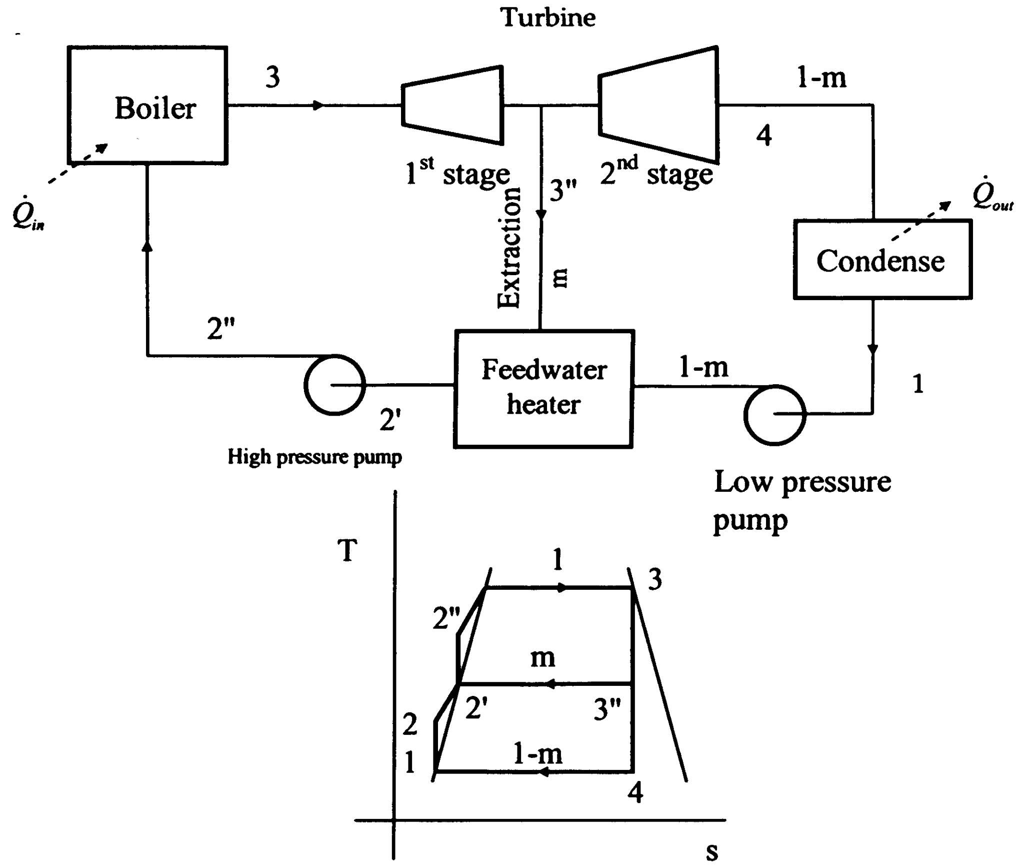


Figure 16 Feed Heating Cycle (ii)

Evidently the heat transfer process in the turbine can be continued until $T_2 = T_3$, whereupon $\eta_{cy} = 1 - T_1/T_3$ which is the Carnot efficiency. Note, however, that the pump work is still small and we have therefore achieved the Carnot efficiency without the penalty of the low work ratio which is a feature of the Carnot cycle itself.

An alternative to the method just described is to carry out the feed water heating external to the turbine by bleeding some steam from the turbine and mixing it with the feed water (figure 16).

This process can be reversible if carried out as follows. The water leaving the condenser is compressed to a pressure whose saturation temperature T is infinitesimally higher than the condenser temperature, and is passed to the feed heater (i.e. the mixing chamber). Some steam is withdrawn from the turbine at a point where its temperature is T and is mixed with the feed water in the heater. The pressure and temperature of the feed water are respectively equal (to within O(dp) and O(dT)) to the pressure and temperature of the steam throughout the mixing process which is therefore reversible. The amount of steam entering the heater is chosen so that it is completely condensed. The feed water and the condensed bled steam are then compressed by a second pump to a pressure at which the saturation temperature is T + dT, steam is again bled and mixed reversibly with the feed water in a second feed heater, delivered at temperature T + 2dT to a third feed pump, and so on. With an infinite number of reversible mixing processes, each producing an infinitesimal temperature rise in the feed water, the feed water may be made to enter the boiler as saturated liquid at T_3. The resulting cycle appears as shown below (figure 1.17). Note that the mass flow rate through the boiler is greater than that through the condenser.

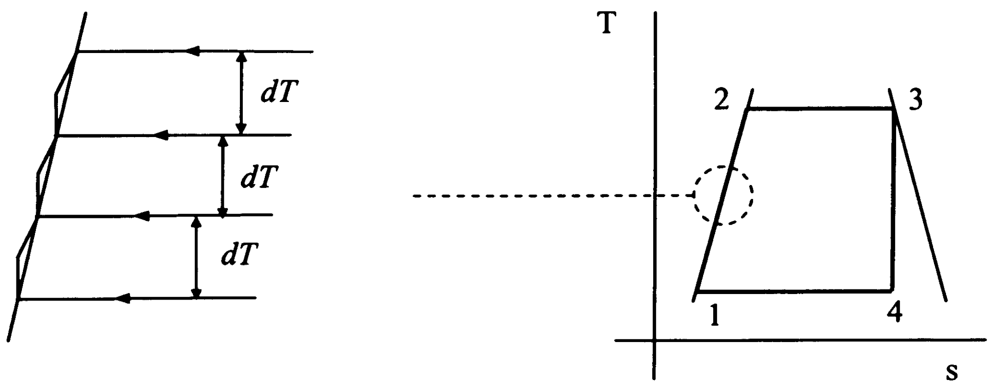


Figure 1.17 Feed Heating Reversibility (ii)

All the heat reception from an external source takes place at the highest temperature in the cycle and all the heat rejection occurs at the lowest temperature. The cycle is also reversible and the efficiency is therefore the Carnot efficiency $1 - T_1/T_3$. This result may also be obtained by noting that since the cycle is reversible the reversible cycles are zero net producers of entropy.

$$m_3(s_3 - s_2) = m_4(s_4 - s_1)$$

where m_3 and m_4 are respectively the boiler and condenser mass flow rates. The efficiency is then

$$\eta_{cy} = 1 - \frac{m_4(h_4 - h_1)}{m_3(h_1 - h_2)} = 1 - \frac{m_4 T_1(s_4 - s_1)}{m_3 T_3(s_3 - s_2)} = 1 - \frac{T_1}{T_3}$$

When the bled steam is superheated and at a temperature lower than the boiler saturation temperature the reversibility of the feed heating can be preserved by bleeding the steam at the feed water saturation temperature and compressing it reversibly and isothermally to the feed water pressure.

Actual Cycle

Irreversiblilities due to fluid friction and heat loss cause the actual cycle to depart from the ideal cycle (figure 18), and with this, a fall in efficiency. Fluid friction causes pressure drops throughout the cycle requiring further work from the pump, while heat loss must be made up by an increase in heat input. Actual cycle analysis is assisted by inclusion of pump and turbine adiabatic efficiencies as explained in the Brayton cycle section.

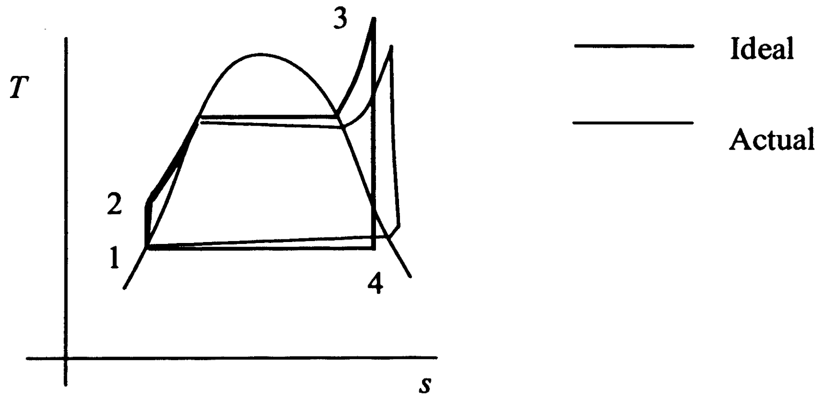


Figure 18 Actual cycle deviation from the ideal Rankine cycle.

Combined Cycle

Gas turbine efficiency is limited by the simple fact that the exhaust gases leave at a high temperature. Intercooling and reheating together with recuperation deliver a considerable improvement in efficiency, but another alternative is to combine the gas power cycle with a vapour power cycle. The gas power cycle exhaust temperatures closely match the heat input temperatures of a steam power cycle, and a heat exchanger can be used in the place of a boiler (figure 19).

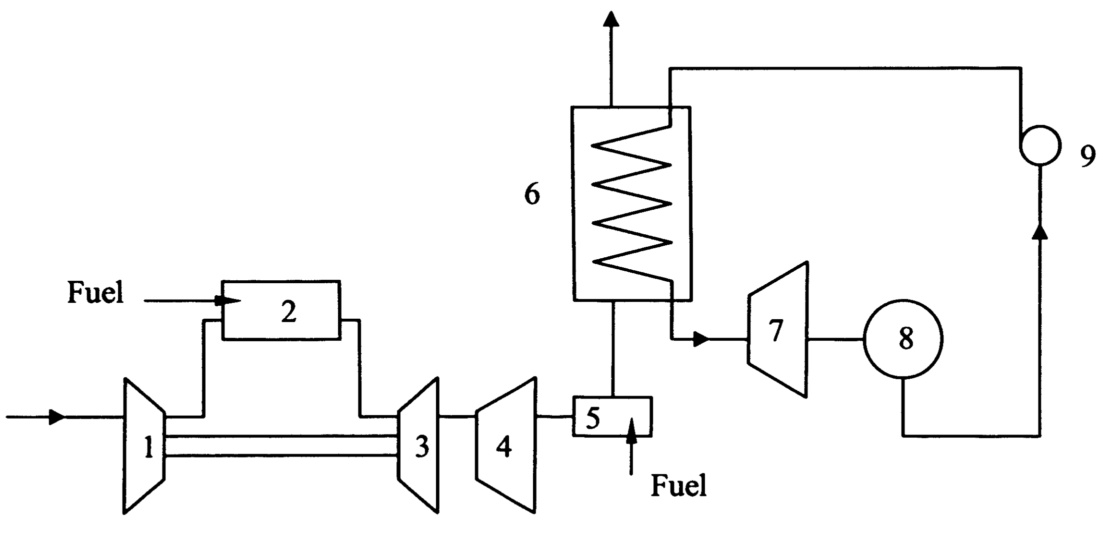


Figure 19 Combined cycle with supplementary firing. 1 Compressor. 2 Combustion chamber. 3 Compressor drive turbine. 4 Power turbine. 5 Possible supplementary firing. 6 Heat recovery unit. 7 Steam turbine. 8 Condenser. 9 Pump. (Bathie)

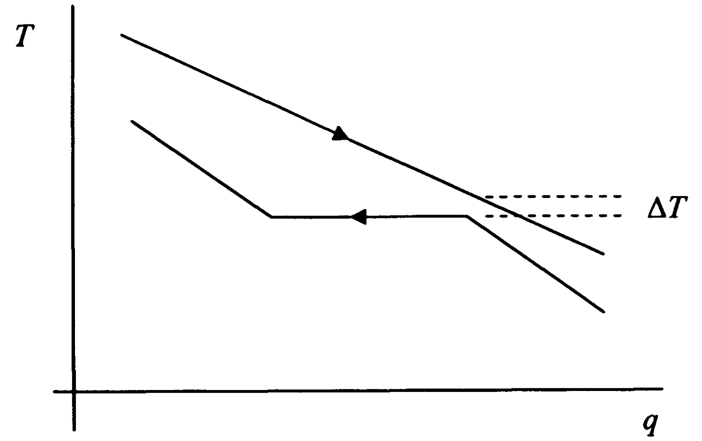


Figure 20 Typical single pressure steam turbine heat exchange diagram (Bathie).

It is important to optimise the collection of the exhaust gas energy in the heat recovery steam generator (HRSG), also termed waste heat recovery unit (WHRU). The heat transfer shown in figure 20 is carried out in three separate stages as the water undergoes a phase change, the economiser, evaporator and superheater sequence being in a counterflow arrangement with the exhaust gases. Increasing the energy transferred is achieved by increasing the heat exchanger surface area which brings the two lines in the figure closer together, decreasing the 'pinch point' temperature difference ΔT. Supplementary firing will increase the fraction of output from the steam turbine and allow control of the HRSG inlet temperature, however it will also increase the cycle heat rate.

For a given gas turbine, the combined cycle overall performance is very much influenced by the steam power plant operating conditions and the pinch point temperature difference. While a high steam pressure will increase steam turbine cycle efficiency, it will also decrease the rate of heat recovery from the exhaust gases. Multiple pressure steam turbine cycles allow for better heat recovery performance (see figure 21) and the use of reheat at intermediate pressure(s) to control steam quality at the turbine exit.

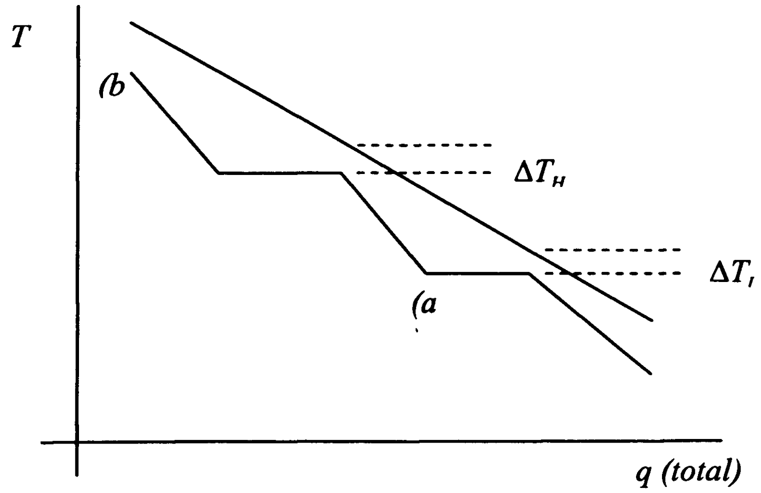


Figure 21 Two pressure steam system heat transfer diagram.

In figure 21 a portion of the low pressure saturated liquid is pressurised further before heating from state (a) to state (b) to provide the high pressure superheated steam, hence the two 'pinch point' temperature differences. The energy recovery process is improved by using multiple pressure systems as the final exhaust gas temperature can be appreciably lower than in the single pressure case.

Power Cycle System Components

GAS TURBINE

The core of a gas turbine consists of a compressor, combustion chambers and a turbine to drive the compressor. The compressor consists of a series of stationary and rotating sets of blades, or stators and rotors. The working fluid is accelerated by the rotor and is then slowed down again to increase the pressure by the stator. Each rotor and stator pair makes up a stage.

'Gas turbine internal combustion is a continuous process taking place at constant pressure. A steady supply of fuel and air mixes and burns as it flows through a flame zone, which is located in the manner of a cloud in the lee of a mountain. The flame does not touch its container, being stabilised by the inlet airflow pattern which also cools the container walls. The combustion process involves very highly developed control of flame stability and can be tuned to emit very low levels of smoke, carbon monoxide, hydrocarbons and oxides of nitrogen.' (Harman)

A turbine stage consists of a ring of nozzle guide vanes directing the flow of hot gas onto moving rotor blades attached to a disc. The process can be repeated, with the possibility for each disc to drive its own independent shaft. Multi-shaft configurations allow power turbines to run at different speeds to that of the engine, and also allow separate compressor sections to operate at their own optimum speeds. The core engine with turbine providing the compressor work only, as in turbojet aircraft engines, is often referred to as a gas generator. 'All aero-derivative gas turbines are of twin shaft type with free power turbine. Heavy duty industrial machines have been developed mainly by steam turbine and diesel engine builders. Light weight industrial gas turbines have been developed using aircraft engine principles in design without having been developed from existing aero engines.'

As firing temperatures can be in the region of 1300°C, high strength materials, corrosion resistant coatings and turbine blade cooling are necessary. Cooling can be achieved by open loop cooling via air from the compressor, or by closed loop steam cooling which can be closely linked to the reheat steam cycle. This aspect is a fundamental restriction on turbine efficiency, as it limits the top temperature of the cycle, and is therefore the main area of effort in design improvement.

'Use of aero-derivative machines gives ease of maintenance due to the modular construction which allows for the complete replacement of the gas generator in 24 hours. Industrial machines require lengthier in-situ maintenance although the time between major overhauls is generally greater than for aero-derivatives and their spares are generally somewhat cheaper.' Also aero-derivatives may require more specialist personnel to carry out maintenance, a factor which may be a problem if swift response to unscheduled work is required. Training of personnel may be necessary for planned and unplanned maintenance.

STEAM TURBINE

Steam turbines also consist of stages which include a ring of fixed blades or nozzles followed by a ring of blades mounted on a wheel. Turbine blades can be impulse or reaction type. Impulse blades deflect the steam jets causing a change in velocity and therefore a change in momentum, while reaction blades act as moving nozzles. As there is a pressure drop across the reaction rotor, there is also a considerable end thrust. Both types of blading may be present in a turbine.

Rotor diameter increases as the pressure falls across the turbine. The turbine's last stage generates up to 15% of the turbine output so the last stage blade design has been an important aspect of recent turbine construction. As pressures can be as high as 165 bar (gauge), and temperatures over 500°C, turbine casing is extremely heavy, and high quality molybdenum, molybdenum-vanadium or chrome-molybdenum steels are required.

Assembly can be modular, facilitating installation. Also, to facilitate inspection, borescopic examination of blades and nozzles can be provided for. The upper half shell can be removed for maintenance of the turbine if all pipes are connected to the bottom half.

WASTE HEAT RECOVERY UNIT (WHRU)

The WHRU will consist of an economiser, an evaporator and a superheater for each pressure steam supply system, arranged in counterflow sequence with the exhaust gas as it travels from gas turbine exhaust to the final exhaust stack. WHRUs generally feature modular construction with finned tube heat transfer surfaces and natural or forced circulation evaporators. There is usually enough waste heat to support a three pressure system, with reheat also applicable in some cases.

Exhaust gas stack temperature is typically about 170°C for a single pressure non-reheat system, and about 130°C for a multiple pressure non-reheat system. If there is sulphur present in the fuel care must be taken not to let the exhaust gas temperature fall below the point at which sulphuric acid will condense inside the heat exchanger components. As this is about 180°C high fuel sulphur content can decrease output and efficiency.

Supplementary firing is also possible to enhance the steam turbine output but is only usually applied in cogeneration applications. 'The incremental efficiency for power produced by supplemental firing is in the 34 – 36% range'. (GE)

Gas Turbine Gas Fuel Requirements

The following table shows gas fuel requirements stipulated by some manufacturers for supply to their gas turbines. Levels of CO and NOx emissions from modern gas turbines are also presented.

Fuel Gas Properties	ABB GTX100	R.-R. RB211	G.E. LM-2500	Solar Mars	Ruston TB-5000
Pressure bar (gauge)	26 (a)	31	27.6	25.5	11
Temperature °C max	120	100	-	-	70
Superheat °C min	20	20	no free liquid	-	20
LHV MJ/Sm^3	24 - 55	-	11.2	39.9 – 41.1	33.6 – 52.3
Wobbe No. MJ/Sm^3	var. +/- 5% (b)	22.4	-	-	-
Solids ppm	20	5	7	10	10
Sulphur (c)	-	1.3 %wt	20 ppm	0.8 %wt	3 %vol
Na + K	0.5 ppm	(d)	(e)	(d)	(f)

Notes

(a) (From ABB technical information document) 'The fuel gas control valve and governor are designed to suit a normal natural gas supply pressure of 27 bar (absolute) at the gas turbine connection point (fire protection shut off valve). Maximum fluctuation is 0.05 bar/sec. The selected pressure has to be kept within +/- 0.5 bar. The required gas pressure is determined by the gas composition and the maximum fuel flow, which is reached at maximum power output, normally appearing at the lowest ambient temperature (or limited by the driven equipment). Higher gas pressure may be required for a low heating value gas or at extremely low ambient condition.'

(b) (Also from ABB) 'Maximum variation of the Wobbe index for all considered gases together shall be within +/- 5%. Maximum acceptable change of the Wobbe index is 0.5%/second.' The fuel gas Wobbe index is the LHV divided by the square root of the relative density (air=1). It represents the potential heat flow through an orifice at constant pressure, and together with fuel flame speed is significant to burner design and operating pressure.

(c) Typically, use of sulphur bearing fuels will not be limited by concerns for corrosion in the hot gas path of the turbine. If heat recovery equipment is used, the concentration of sulphur must be known as severe corrosion from condensed sulphuric acid can occur in the WHRU.

(d) Na, K restricted

(e) V, Na restricted

(f) Na restricted

EMISSIONS

CO

Highly efficient combustion keeps carbon monoxide emissions as low as 5-25 ppmvd (parts per million by volume (dry)). 'Catalytic CO emission abatement systems are also available, if required, for lower emission rates. In a combined cycle configuration the CO catalyst is installed in the exhaust gas path, typically upstream of the WHRU superheater', i.e. immediately after the gas turbine exhaust.

NOx

While CO emissions will increase if not enough oxygen is present at combustion, NOx emissions will increase if there is too much. Most turbines have Dry Low NOx (DLN) combustors that can provide exhaust gas NOx emission concentration as low as 9 ppmvd at 15% oxygen (gas fuel), without water or steam injection (which would reduce plant efficiency). Selective catalytic reduction can be carried out using ammonia and a catalyst to reduce NOx to nitrogen and water, thus reducing NOx emissions still further to less than 9 ppmvd at 15% oxygen. This process operates at between 400 and 300°C so can be situated between superheater and evaporator in the WHRU.

Electricity Generating Cost

Electricity generating costs are either taken directly from manufacturers or given by expressions dependent on engine development (industrial or aero-derivative). The expressions used are given below.

Costs presented are for the CCGT plant. Any simple cycle plant costs used in the Economic Model in Chapter Six come directly from the manufacturers. Costs are dependent upon the number of gas turbines and steam turbines used and their powers (N_{GT}, N_{ST}, MW_{GT}, MW_{GT} respectively).

<u>Aero-derivative GT Based Plant</u>

$$\text{Cost} = N_{GT} \times (8.5 + 0.253 \times MW_{GT}) + N_{ST} \times (4.2 + 0.123 \times MW_{ST}) \text{ (£M)} \quad \text{(E 5.7)}$$

<u>Industrial GT Based Plant, ~45 MW unit output</u>

$$\text{Cost} = N_{GT} \times (1.7 + 0.213 \times MW_{GT}) + N_{ST} \times (4.2 + 0.123 \times MW_{ST}) \text{ (£M)} \quad \text{(E 5.8)}$$

<u>Industrial GT Based Plant, ~150 MW unit output</u>

$$\text{Cost} = N_{GT} \times (6.7 + 0.123 \times MW_{GT}) + N_{ST} \times (4.2 + 0.123 \times MW_{ST}) \text{ (£M)}$$

(E 5.9)

Item	**Cost (£ Million)**
Basic Vessel (including DPS and Gas Processing Plant	66.3
Electricity Generating Plant	153.7
CO_2 Sequestration Plant	92.2
Electrical Equipment (e.g. swithgear, transformer, filter etc.)	44.2
Total	**379.0**

Cost of the 'Base Case' CEPV

A breakdown of the total cost of the Base Case CEPV is shown in Table 5.7. The total cost of the Base Case CEPV is £379 million. The total cost for the construction of the basic vessel is £66.3 million accounting for material, fabrication and construction. A base construction cost is then derived from this by percentage increases for EPCS (engineering, procurement, construction and supervision), operator costs (engineering costs incurred by others) and insurance. Finally a total cost is obtained by adding a contingency cost to the base construction cost (a further percentage increase). The total cost of electricity generating plant is £153.7 million. This cost is considered either directly from manufacturers' prices or from formulae derived from an industry-wide survey. The total for CO_2 sequestration plant is £92.2 million. Costs are a multiple (60%) of the generating plant cost. This is based upon observations of existing sequestration plant using Amine Scrubbing, taken from a 392 MW plant example. The total cost of electrical equipment is £44.2 which includes switchgear, transformer, filter etc.

Appendix 2

Electricity Transmission Schemes

Six viable transmission systems have been identified for investigation, three DC transmission systems and three AC transmission systems.

DC Single Core with Sea Return

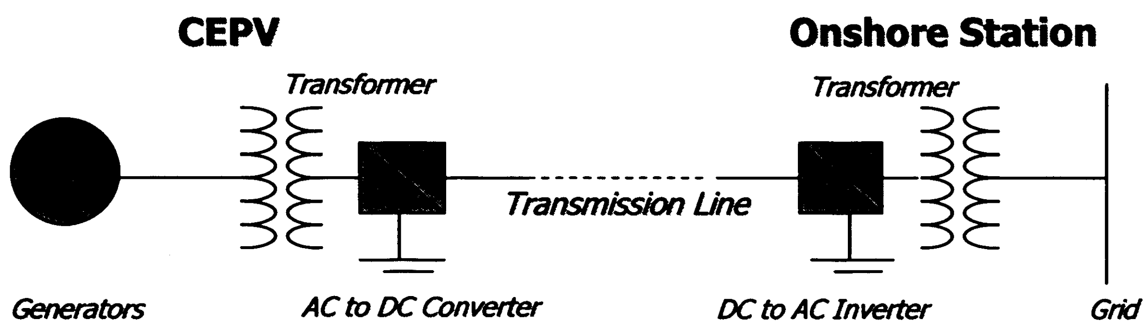


Figure 1 DC Single Core with Sea Return

DC single core cable with a sea (ground) return is a transmission system based upon conventional AC generation and transmission by high voltage direct current (HVDC). The CCGT Plant and generators, transformers and the AC-DC converter is provided onboard the CEPV. The subsea transmission cable has a single conductor. The shore-based station has a DC to AC inverter and transformer to allow integration to the National Grid. Protection and harmonic filtering is also required at both ends of the transmission line. Return current is via sea electrodes. Examples of this system include:

Project	Distance	Voltage	Power
Fenno-Skan	200km	400kV DC	500 MW
Sweden-Germany link	250km	450kV DC	600 MW

Table 1: DC with Sea Return

Advantages:

- Only one cable with one conductor is needed hence low cable cost.
- Simple and established system.
- Negligible losses in sea return (multi-path return).
- Only real power is transmitted through the cable.

Disadvantages:

- Rectifier needed offshore.

- Sea return is likely to cause corrosion of local metal pipe-work, etc.
- No redundancy in case of a conductor cable fault.
- Losses occur in the converter and inverter.
- AC harmonic filtering is needed at both ends of the transmission line.
- Possible disturbance to marine habitats (sea returns).
- Sea electrodes may be more expensive than a return cable.

DC Single Core with Metallic or Conductor Return

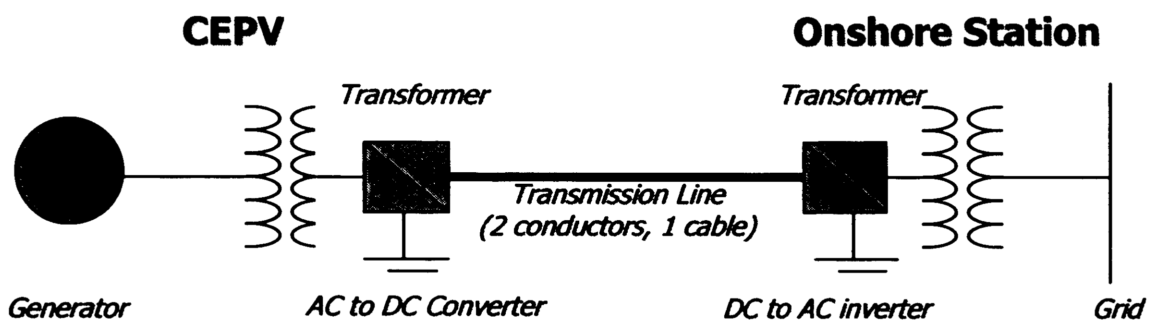


Figure 2 DC Single Core with Metallic/Conductor Return

DC single cable with a conductor return (i.e. two core cable) is a transmission system based upon conventional AC generation with transmission by high voltage direct current (HVDC). The CCGT Plant and generators, transformers and the AC-DC converter is provided onboard the CEPV. The subsea transmission cable has two conductors either in a Møllerhøj or Integrated Conductor Return (ICR) design. The shore-based receiving station has a DC to AC inverter and transformer to allow integration to the National Grid. This system can be designed to be used as a monopolar (e.g. +200kV, 0V) or bipolar (e.g. +200kV, -200kV) or unipolar (e.g. +200kV, +200kV) with metallic or conductor return. Reversionary modes are possible using the sea return. Protective and harmonic filters are also required.

DC Møllerhøj and ICR transmission cables have an integrated return conductor within the same cable. The difference between Møllerhøj and ICR being that Møllerhøj is a cable with 2 adjacent conductors whilst the ICR cable consists of a main conductor with a concentric outer return conductor. Examples of this system type are:

Project	Distance	Voltage	Power
Moyle (ICR)	64 km	250 kV DC	2 x 250 MW
Denmark – Germany (Møllerhøj)	170 km	400 kV DC	600 MW

Table 2 DC Single Core with Conductor Return

Metallic return is different from two conductor designs by the fact that these designs are mostly monopolar designs with the return being at or near ground potential. Consequently, the insulation requirements for the return cable are much less than that required in a bipolar regime. An example of this system is:

Project	Distance	Voltage	Power
Basslink (Australia)	295 km	400 kV	600 MW

Table 3 DC Single Core with Metallic Return

Advantages:

- Simple and established system.
- Only real power is transmitted through the cable.
- Two core cables are more expensive than metallic return.

Disadvantages:

- Rectifier needed offshore.
- Losses in converter and inverter.
- Losses in transmission and return conductors.
- AC harmonic filtering needed at both ends of the transmission line.

DC Two Cables

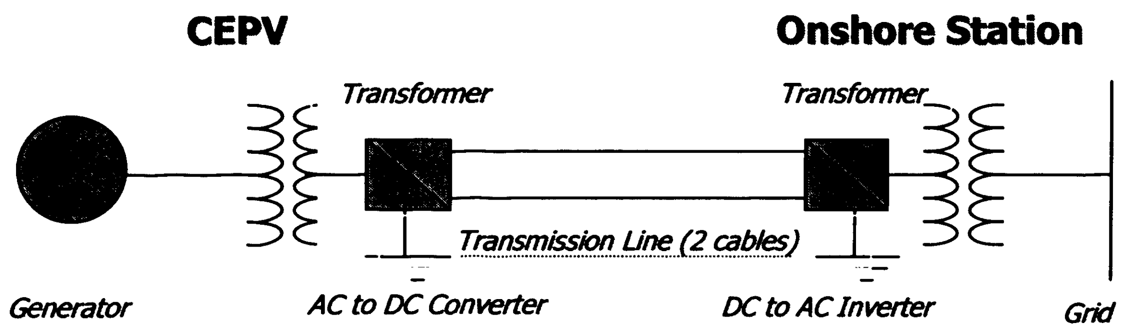


Figure 3 DC Two Cables

DC two cables is a DC transmission system employing two separate cables. One cable is used for transmission and the other is used as a return. The transmission system uses conventional AC generation with transmission by high voltage direct current (HVDC). The CCGT Plant and generators, transformers and the AC-DC converter is provided onboard the CEPV. The shore based station has a DC to AC inverter and transformer to allow integration to the National Grid. Each independent subsea transmission cable has a single conductor and the system can be designed to be used as a monopolar (e.g. +200kV, 0V) or bipolar (e.g. +200kV, -200kV) or unipolar (+200kV, +200kV) using sea return. Examples of this system type are:

Project	Distance	Voltage	Power
Skagerrak	124 km	350 kV DC	500 MW
Cross Channel	50 km	270 kV DC	2 GW

Table 4 DC Two Cables

Advantages:

- Simple and established system.
- Only real power is transmitted.
- Redundancy if one cable fails.

Disadvantages:

- Losses in converter and inverter.
- Losses in transmission and return conductors.
- AC harmonic filtering needed at both ends of the transmission line.
- Two cables hence greater cable costs and cable-laying costs.

AC Three Cables

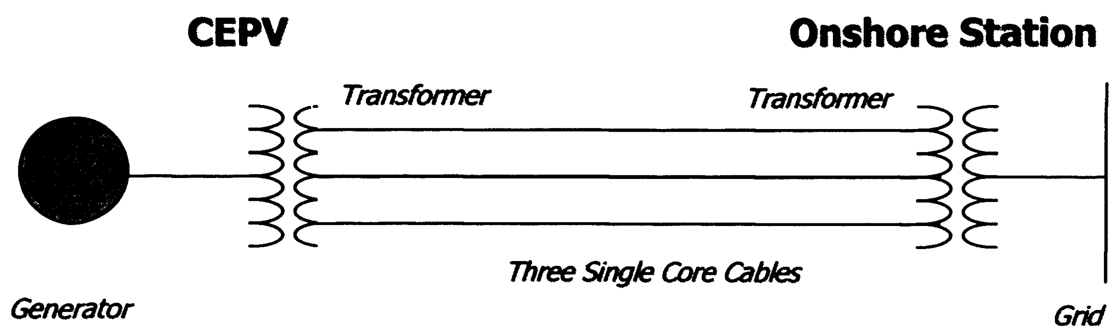


Figure 4 AC Three Cables

The AC three cable option is based upon conventional generation with transmission by three-phase high voltage alternating current (HVAC) cables. This method of transmission uses independent cables typically laid at 5 m apart. An example of this system is:

Project	Distance	Voltage	Power
Cebu-Leyte (Philippines)	32.5km	230 kV	500 MW

Table 5 AC Three Cables

Advantages:

- No requirement for converters.
- No requirement for harmonic filtering.
- Potentially smaller cable sizes than required for DC.

Disadvantages:

- Transmission distance limited due to cable capacitance.
- No decoupling between the AC generators on the CEPV and the grid.
- Charging current every cycle hence real and reactive power flow.
- Real and reactive current flows between the two AC systems which can only be reduced with additional compensation equipment.
- Increased cost because of the need for three cables and the increased cost of laying.

AC One Cable with Three Conductors

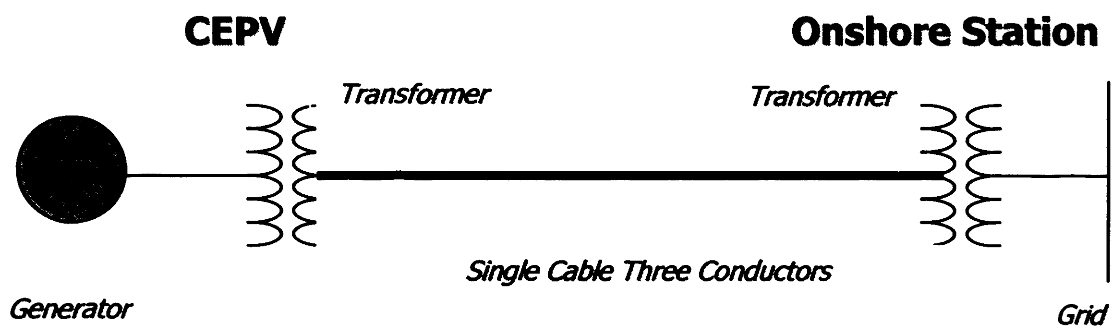


Figure 5 AC One Cable with Three Conductors

The AC one cable option is based upon conventional generation with transmission using a three-phase HVAC cable having three conductors. The CEPV houses only the CCGT Plant, generators and transformer. Example of this system includes:

Project	Distance	Voltage	Power
Belize	19.3km	46kV	10 MW

Table 6 AC One Cable with Three Conductors

Advantages:

- No requirement for converters.
- No requirement for harmonic filtering.
- Reduced cost i.e. laying only one cable.

Disadvantages:

- Transmission distance limited due to cable capacitance.
- No decoupling between AC systems on CEPV and the Grid.
- Charging current every cycle hence real and reactive power flow.
- Real and reactive power can only be reduced with additional compensation equipment.
- Cable diameter and cable complexity means greater manufacturing costs.

AC Low Frequency

Type A

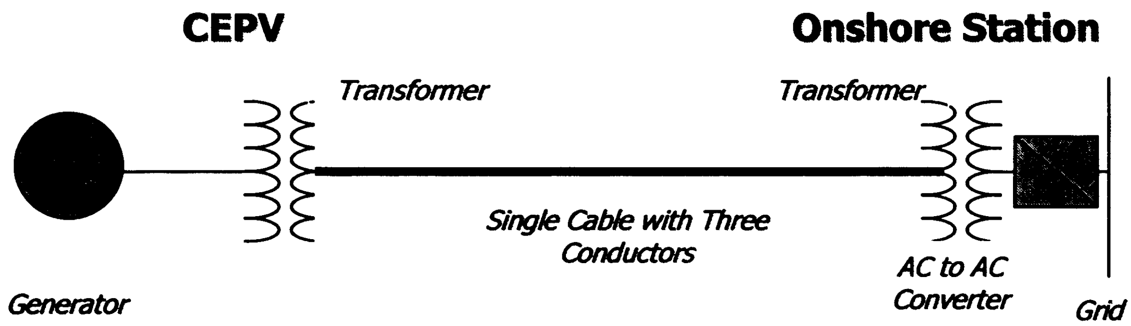


Figure 6 AC Low Frequency Type A

The transmission system is based on a low frequency generating system and transmission by a three-phase high voltage low frequency (HVLF) transmission cables to an AC-AC inverter onshore. The AC to AC converter changes the low frequency transmitted power into a standard frequency to allow integration to the National Grid.

Advantages:

- No converter required onboard the CEPV.
- Decoupling between AC systems offshore and onshore.
- Use of conventional generator technology running at lower speeds.
- Potentially greater transmission distances than standard AC with reduced losses.

Disadvantages:

- Generator speed may not match prime-mover speed (gearbox needed).
- Machines and transformers are larger since they operate at a lower frequency ($Physical\_Size \propto \frac{Power}{Speed}$).
- Limited lower frequency because of limitations in prime-mover rotational speed.
- Non-standard system and no previous experiences.

Type B

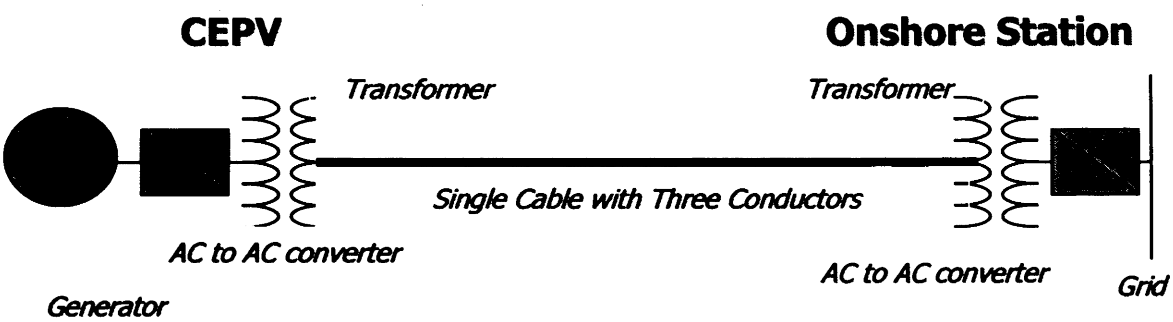


Figure 7 AC Low Frequency Type B

This transmission system is based on standard frequency generation with transmission by a three-phase high voltage low frequency (HVLF) cable to the receiving station onshore. The generators onboard the CEPV generates electricity at a standard frequency and the offshore converter reduces the generated frequency for transmission purposes. The shore-based power station uses a frequency converter which changes the transmission frequency to the grid frequency and transformers to match transmission and National Grid voltages.

Advantages:

- Conventional generation at 50 Hz.
- Decoupling between AC systems offshore and onshore.
- Greater transmission distances possible than standard AC transmission.

Disadvantages:

- Frequency converters are needed hence greater cost.
- Converters may need to be specialist types.
- Probable harmonics generated by converter hence need for filtering.
- Non-standard system and no previous experiences of such systems.

Appendix 3

Power Conversion Technologies

1. Introduction

For HVDC transmission, converter is needed onboard the CEPV to change the generated power at 50 Hz into HVDC suitable for transmission. At the shore-based receiving station, an inverter is needed to change the transmitted DC back into AC at 50 Hz suitable for synchronisation and integration to the grid.

Converters, inverters and frequency changers generally require additional equipment in the form of control systems, cooling systems, filters (to remove unwanted harmonics and maintain power supply quality) and switchgear.

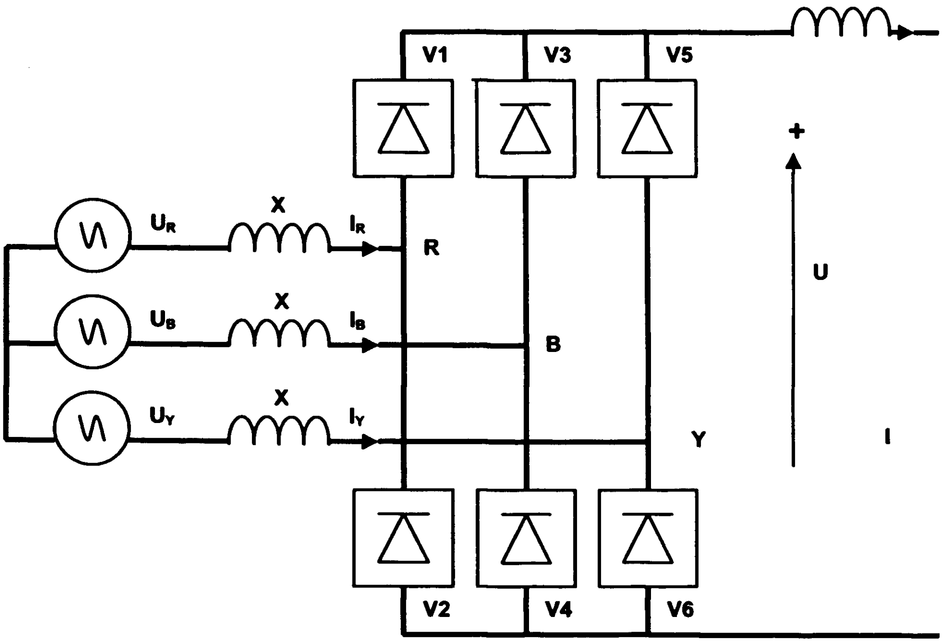
2. High Voltage Direct Current (HVDC)

Technology Overview

HVDC technology is commonly used to transmit electrical power over long distances by subsea cable. It is also used for overhead HVDC transmission systems and to interconnect separate power systems, where an AC connection cannot be easily used.

A large number of HVDC transmission systems exist all over the world and many decades of experience have been gained. Advances in HVDC performance over time have increased efficiency and reliability. The 'classic' HVDC transmission system, known as the back-to-back Graetz bridge as shown in Figure 4.8, has developed into a mature, cost-effective, reliable and well established technology.

In HVDC systems, the conversion or rectification of electrical current from AC to DC occurs at the transmitting end and inversion from DC back to AC occurs at the receiving end. Three different methods of conversion and inversion can be employed in HVDC systems, the key differences being the type of power electronic device employed and the means of commutation used.



Note: Diodes are shown which would be a simpler rectification process however thyristors would provide regulation and improve control e.g. charging current at start.

Figure 1 Graetz Bridge

Natural Commutated Converter/Inverter (NCC/I)

NCC is the classic Graetz Bridge employing thyristor stacks (thyristor semiconductor devices connected in series) arranged two per phase. The Graetz Bridge used in the classic back-to-back arrangement allows conversion at the sending end (NCC) and inversion at the receiving end (NCI). The thyristor switches are turned-on in a predefined sequence by a control circuit using a gating signal (usually an electronic or light trigger) but turn-off occurs when the alternating current naturally reverses through the thyristor each half cycle. The output voltage and flow of current may be controlled by means of applying a firing angle delay. For inversion to operate successfully, it is necessary for there to be a stiff AC supply at the inverter output terminals otherwise commutation (turn-off) will not be achieved satisfactorily. This may lead to mal-operation of the converter.

Capacitor Commutated Converters/Inverters (CCC/I)

These are similar to the NCC/I except that the thyristors are turned-off by commutation capacitors placed in series between the converter transformers and the thyristors. This design tends to be preferred where the Grid network is weak. There are significant additional costs associated with the commutation capacitors.

Forced Commutated Converter/Inverter (FCC/I)

Voltage source converters (VSC) and inverters (VSI) use gate turn-off thyristors (GTO) and insulated gate bipolar transistors (IGBT) or another such similar fully controlled device. Fully controlled means that the device can be turned on and off by a control signal rather than relying upon the power circuit's natural current reversal as for the thyristor. Forced commutation also differs from the NCC/I and the CCC/I types because pulse-width-modulation (PWM) switching techniques are normally used to improve output waveform quality. The devices switch more rapidly than thyristor devices (between 10 and 60 times as fast) producing superior voltage output waveforms minimising the need for harmonic filters.

HVDC Schemes

The converter types discussed in the previous section can be used in various HVDC schemes. The 'classic HVDC scheme' usually employs the NCC/I or CCC/I when connected to an electrically weak Grid. HVDC Light uses the FCC/I but has tended to be favoured for lower power applications.

Monopolar and bipolar HVDC transmission

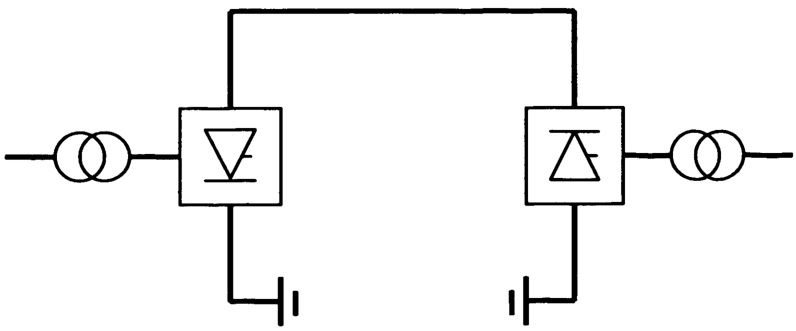


Figure 2 Monopolar Transmission System

Most existing DC transmission systems use the classic HVDC scheme. These are point-to-point transmission systems that use either overhead lines and/or subsea cables. Most subsea cable configurations are monopolar with the cable having a single conductor laid between the converter and receiving station and current return being facilitated via electrodes placed in the ground or sea. This design requires a minimum of two Graetz Bridges as shown in Figure 2.

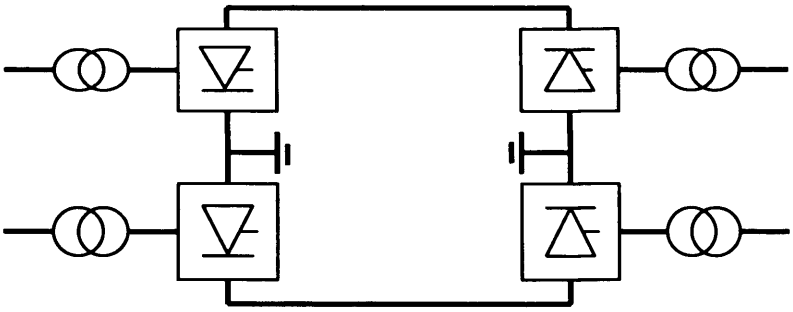


Figure 3 Bipolar Transmission System

An alternative to a monopolar design is the bipolar design. A bipolar transmission system resembles a twin-monopole circuit utilizing two conductors of opposite polarity, one positive and one negative. A bipolar transmission system requires a minimum of four Graetz Bridges as shown in Figure 3. The bipolar design can revert to monopole operation during maintenance or failure of converter, inverter or cable.

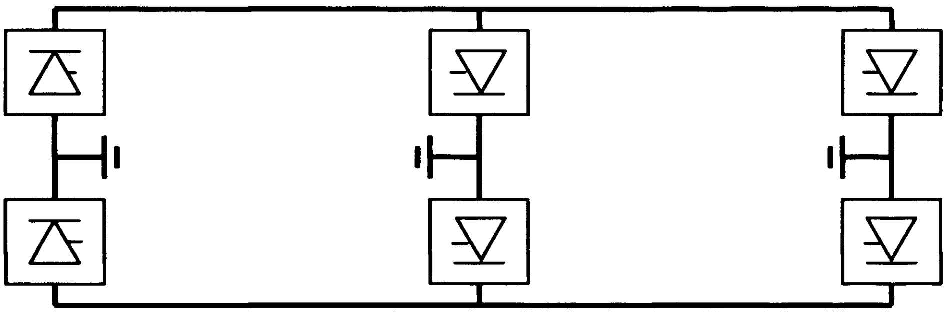


Figure 4 Multi Terminal

A multi-terminal transmission system is shown Figure 4. An example of this system is the 2000 MW Hydro Québec and New England multi-terminal HVDC system opened in 1992. The transmission system allows multiple sending stations and multiple receiving stations to be connected to common cables. Although more complex than the simple point-to-point transmission system, a multi-terminal transmission system offers the potential to integrate other generating capacity e.g. renewable energy (assuming it is geographically possible to do so) thereby sharing cable costs between a number of offshore generating companies. NCC/I, CCC/I, and VSC/I technology has the potential to be integrated into multi-terminal systems.

Cycloconverter

The cycloconverter is a thyristor based technology capable of changing a standard frequency supply into a low frequency output. The cycloconverter operates by cascading sections of the input waveforms to form a low frequency output waveform which can be up to 33% of the input waveform e.g. 16.25 Hz for a 50 Hz system. It is also capable of inverting low frequency into a standard output frequency supply. The cycloconverter is therefore able to operate in the converting and inverting modes.

The disadvantage of the cycloconverter is its physical size since it requires a minimum of 36 thyristor valve stacks for a three phase system. The cycloconverter is therefore six times the physical size of a Graetz bridge used in a HVDC scheme.

Furthermore, when operating in a fully inverting mode, very careful operation is needed to avoid mal-operation.

Cycloconverters are used by rolling mills in the steel industry and also as a variable speed drives in ship propulsion systems. Consequently, cycloconverters are made only at modest voltage and power ratings typically 11 kV and 20-40 MW. In an offshore electrical power station, 200 kV and 250 MW are proposed. A cycloconverter at these ratings has never been constructed. Consequently, costs are too difficult to estimate and the volume of such a converter is also unknown.

Pulse Width Modulation

The alternative is to employ VSC/I using Pulse Width Modulation strategies. At the sending end the VSC would first need to rectify the standard frequency and the VSI would change DC into a low frequency output power. At the receiving end a VSC would rectify the low frequency transmitted power to produce DC and the VSI would change the DC into the standard AC frequency ensuring compatibility with the Grid. Note that a two stage conversion process is now required at the offshore and receiving station.

The use of two converters and two inverters in a HVLF scheme will be less efficient than an equivalent HVDC transmission system. Furthermore, the need for the additional space would make such a solution uncompetitive.

For the future Matrix converters are likely to develop from university research into mature technologies. Matrix converters allow frequency conversion to be achieved in a single stage. Matrix converters are small and operate at high switching speeds hence they generate good quality output waveforms. Although such power electronic systems are attractive and suitable for low frequency systems they are unlikely to be available for some years.

3. Components for a Conventional HVDC Transmission

Valve stacks

Key aspects of the valve stack design are:

- A valve stack contains a significant number of semiconductors (thyristors, GTOs or IGBTs) connected in series (to share the voltage drop) and parallel (to divide the current).
- The thyristor valves are normally grouped together and arranged in structures and are usually suspended from the ceiling of the valve hall to allow for thermal expansion.
- Water cooling is normally used in a closed loop de-ionised water system with cooling water (CCCW). For IGBTs direct seawater cooling has been developed for lower powers.
- A computer generates electrical gate pulses and these trigger the thyristor valves into conduction. Delivery of the trigger signal is by small electronic thyristor control unit (TCU).

Transformers

Transformers are used in HVDC systems and serve several important functions namely:

- They match voltage levels between generators, transmission and Grid systems.
- Supply multi-phase supplies using phase-shifting techniques to allow 6, 12, 18 and 24 pulse converters and inverters to be used. Higher pulse number converters improve waveform quality but require the use of additional bridge networks.
- Act to provide a galvanic barrier between AC generator and Grid systems and the DC transmission systems.
- Additional impedance of the transformer reduces short-circuit current levels and acts to control the rate of rise in thyristor valve current during commutation.
- A transformer having a tap range with small incremental steps provides for necessary adjustments in supply voltage as power demand changes, without compromising converter efficiency.

Reactive power demand and AC filters

Under normal operation, a converter may consume reactive power in an amount that corresponds to approximately 50 % of the transmitted active power. The least costly way to generate this reactive power is by using shunt connected capacitor banks which when combined with series reactors and resistors form filters to reduce converter generated harmonics. The alternative to using filters is to employ harmonic tolerant generators having a high reactive power capacity or to use static VAR compensation systems.

Smoothing reactor

A reactor is normally connected in series with the converter in the DC link (usually at both the transmitting and receiving ends) to:

- Reduce the harmonic currents on the DC side of the converter hence smoothing
- Reduce the risk of commutation failures by limiting the rate of rise of the DC line current under transient AC line disturbances
- Reduce the rate of rise in current when faults occur through damage to the cable.

DC filter

The smoothing reactor is used together with parallel capacitors to filter DC side harmonics. The filter types used on the DC side are similar to those used on the AC side i.e. series resonance filters and low pass filters. The largest and most expensive item of a DC filter is the capacitor.

Control system

Control is normally achieved with the converter controlling the DC transmission voltage and the inverter controlling the current or power flowing through the DC link. The control systems use computer based algorithms that act to adjust the firing angle delay of each thyristor valve and to adjust tap changer position on the converter transformers. For bipolar HVDC links the control systems are similar but duplicated for the additional converter and inverters employed. Usually, the control systems at each station (transmitting and receiving ends) communicate with each other through a dedicated telecommunication link. Remote operation from the Grid Control Centre controls power flow into the grid.

Switchgear

In the CEPV scheme, the function of the switchgear will be to protect the generators, the transmission system and the Grid system against mal-operations. The switchgear and associated measurement and control systems must be capable of safely clearing any faults which may occur in any part of the electrical system. It must also provide the facility for segregating parts of the network by earthing sections so allowing safe access to component parts for maintenance and repair. The main types of switchgear are air-breakers, vacuum-breakers and SF6-breakers. For the CEPV when a 250 MW CCGT Plant is used, the choice is reduced to SF6 breakers and these can only be fitted on the AC side.

4. Converter Solution for the CEPV

For very high power HVDC transmission systems, choice is limited to NCC and CCC technology in a monopolar or bipolar configuration. FCC technology is currently available at more modest power levels and voltages.

The electricity generator onboard the proposed Base Case CEPV rated at 250 MW and 200 kV is at the present limit of FCC technology using a single bipolar cable arrangement. However the improved waveforms and minimal reactive power demand makes the FCC converter technology very attractive for the CEPV. Furthermore these converters are both light and compact, requiring minimal auxiliary equipment.

The main drawbacks of FCC/I is that it is likely to be more expensive than a conventional system and there will be greater losses because of increased switching rates. Experience of these systems is limited although the commercial development step to 200-300 MW systems has been made with the Cross-Sound Cable link in the USA (2002) and the Murraylink in Australia (2002).

The cost of a bipolar 200kV, 250 MW DC link transmission system using FCC/I technology e.g. the 'HVDC light technology' offered by ABB, is expected to be in the region of $100M.

VSC Transmission provides greater independence and flexibility at each end of the transmission line allowing precise voltage and frequency control of the low harmonic output waveforms. The VSI is also capable of supplying passive AC networks.

Appendix 4

Subsea Cable Transmission Technologies

Introduction

For HVDC transmission, possible cable solutions are; Single core sea return; single core metallic return; integrated conductor return (ICR, bipolar), Møllerhøj (bipolar) and two cables.
For HVAC transmission possible cable solutions are; Single core cables in flat formation; single core cables in trefoil formation, three core cables and three single core cables.

The aims of this section are:

- To review existing subsea cable design.
- To consider cable losses.
- To propose a suitable HVDC cable for the CEPV.
- To propose a suitable HVAC cable for the CEPV.

A technical and economic appraisal of subsea power cables is an important part of this work. The anatomies of various cable types have been studied in detail with each cable type being analysed to determine its suitability for use on the CEPV.

An optimum cable design is to be proposed for the HVDC and HVAC systems. This information once imported into the economic model will determine the break even distance between HVDC and HVAC.

Cable Types

Introduction

Cables consist of conductor(s), insulation layers, sheathing and armouring. The main conductor types are aluminium (Al) and copper (Cu). The cross sectional area for a conductor will depend upon the resistivity of the conducting material, the current being transmitted and permitted operating temperature.

The main types of insulation are cross linked polyethylene (XLPE), self-contained fluid filled (SCFF), ethylene propylene rubber (EPR) and mass impregnated non-draining paper (MIND). The thickness of the insulation largely depends upon the selected voltage level. The sheathing is usually lead (Pb) and the cable is grounded to carry fault currents should the cable be damaged. The armouring is usually galvanised steel covered with polypropylene (PP) yarn and bitumen to provide protection against external cable damage.

Three main types of subsea power cables normally used are:

- Self contained oil filled (SCOF)
- Mass Impregnated Non-Draining paper (MIND)
- Extruded insulation e.g. cross linked polyethylene (XLPE).

The type of cable selected for a particular application depends upon the method of electrical transmission, the transmitted power, the voltage level and the environment in which the cable is to be sited.

Oil-filled cables

Historically, oil filled cables have been used for AC subsea transmission systems although technically they may also be used for short distance DC transmission systems.

A typical oil filled cable has a central conductor which is insulated with paper impregnated with synthetic oil, the pressure being maintained by pumps placed at the cable ends. The need for pressurising pumps restricts the length of these cable types to less than 50 km. For longer cables, intermittent pumping stations would be needed, typically at 25 km or so. However such practice is not commonplace for subsea cable designs and such designs are likely to be very expensive.

Leakage from oil filled cables can lead to the suspension of power transmission and the oil may also become an environmental hazard. Oil filled cables require additional auxiliary equipment (pumps, piping, and header tanks) over other cable types which increases cable purchase costs and its through life maintenance costs.

These additional costs combined with the potential environmental risks and the need for long transmission distances for the CEPV mean that this cable type is less attractive than other cable types. Furthermore the use of such cables has been reduced worldwide for the reasons already mentioned and because of the development of alternative cable designs having lower losses and lower manufacturing costs.

Mass Impregnated Non-Draining Cables (MIND)

One of the main use of Mass Impregnated Non-Draining paper insulated (MIND) cables is for DC transmission systems and cables of this type have been designed to withstand voltages up to 500 kV. They are also used in AC transmission systems up to 230 kV.

A typical MIND cable has a central conductor which is insulated with paper impregnated with a viscous non-draining compound such as micro crystalline waxes or resins. Unlike the oil filled cables there are no pumping requirements. The non-draining compound prevents fluid draining to the lower part of the cable where installations have high elevation differences. This may occur in deep water and where there are changes in elevation of the seabed.
The MIND cable is often favoured for both AC and DC transmission systems because it is economically attractive. Purchase costs and through life maintenance costs (no pumping stations required) are usually lower and consequently, MIND cables have been used in a great number of AC and DC transmission system projects.

Extruded Insulation Cables
In recent years, extruded insulated cables have been used in preference to oil filled cables and MIND cables for many AC transmission projects. XLPE is not considered to be a serious option in HVDC transmission systems at any significant power levels since this type of insulation tends to break down in the presence of a DC current. It is not fully understood why this occurs but it is suspected that the polarising effect of DC causes premature degredation. Continued development should lead to improvements of these insulating material types for DC applications in the future.

A typical extruded insulation cable has a central conductor insulated with polymeric material such as cross linked polyethylene (XLPE) or ethylene propylene rubber (EPR). Generally, extruded insulation cables have a lower capacitance per unit length than MIND cables resulting in lower loss in AC transmission systems. The other main advantage of XLPE cables is that they tend to be less expensive than oil filled cables and can be more easily used for longer transmission distances.

For AC transmission systems it is accepted that XLPE or EPR insulated cables are more advantageous as compared with MIND insulated cables because of improved thermal, mechanical and electrical properties.

Optimum Subsea Transmission Cable for the CEPV

Optimum HVDC Cable Design

This parametric survey is concerned with identifying the optimum electricity export cable for the proposed Base Case CEPV. By considering the ratings of the CEPV's onboard generators and operational profiles of each cable types, it is possible to obtain the optimum cable for both DC and AC scenarios. The results of this parametric survey is then used in an economic analysis to ascertain the breakeven distance between DC and AC by considering gas field size and distance to shore.

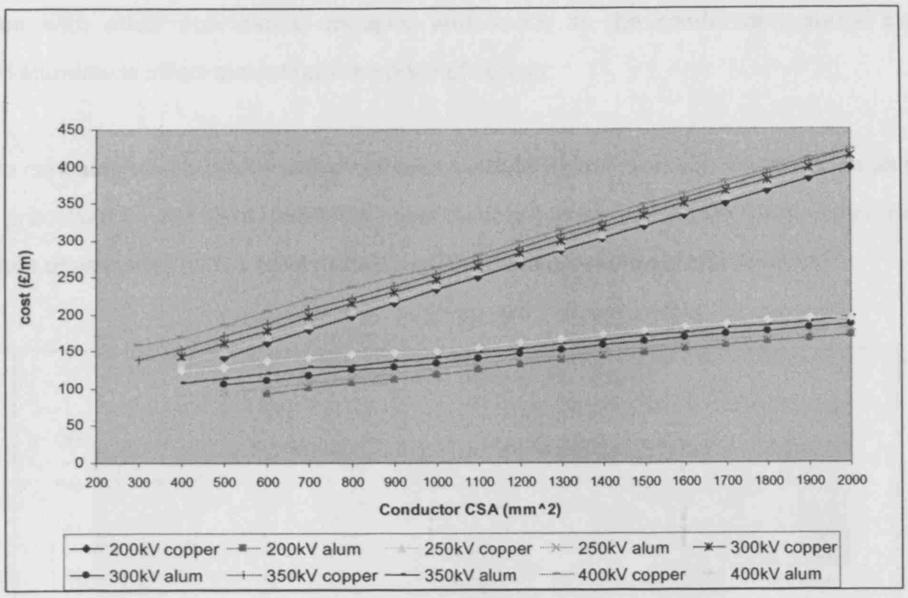


Figure 1 Costs of single core cables per meter.

It is expected that cable optimisation will be based upon the cable costs and converter costs as total cable losses are low. The most important parameter for comparison will be total cable cost which is related to the conductor material and cross sectional area, operational voltage and the costs of conducting return current. Costs of single core cables are shown in the Figure 1. It can be seen that cable costs increase linearly with the conductor size. It can also be seen that the highest cable costs are at 400kV while the lowest cable cost occurs at 200kV.

From the modelling of DC cable the optimum cable for each option can be obtain and for the purpose of comparison they are presented in Table 1.

Design Option	Voltage Level	Conductor Material	CSA (mm^2)	Cost (£/m)	Losses (MW/km)	Converter Cost (£)	Electrodes (£)
SC	200kV	aluminium	700	103.9	0.073	50 million	5.3 mil
MR	200kV	aluminium	1300	257	0.046	50 million	-
ICR	200kV	aluminium	1000	147	0.051	50 million	-
Møl	200kV	aluminium	800	221	0.146	50 million	-

SC: Single Core with sea return, MR: Metallic Return, ICR: Integrated Conductor Return, Møl: Møllerhøj

Table 1 Optimum DC cables

Several observations can be made from the comparison above. It can be seen that the optimum cables operate at the selected lower voltage (200kV). It can also be observed that these cables have aluminium core. These two observations are justified as the converter cost for 200kV is the lowest in comparison with other operational voltages, and as far as the conductor material selection is concerned aluminium offers almost half the price of copper.

In order to conclude which of the above selections would be the favoured HVDC option all the above data was processed by the Economic Model and the Internal Rate of Return (IRR) results for different general sizes of gas fields with a base distance of 75km are presented in the Figure 2.

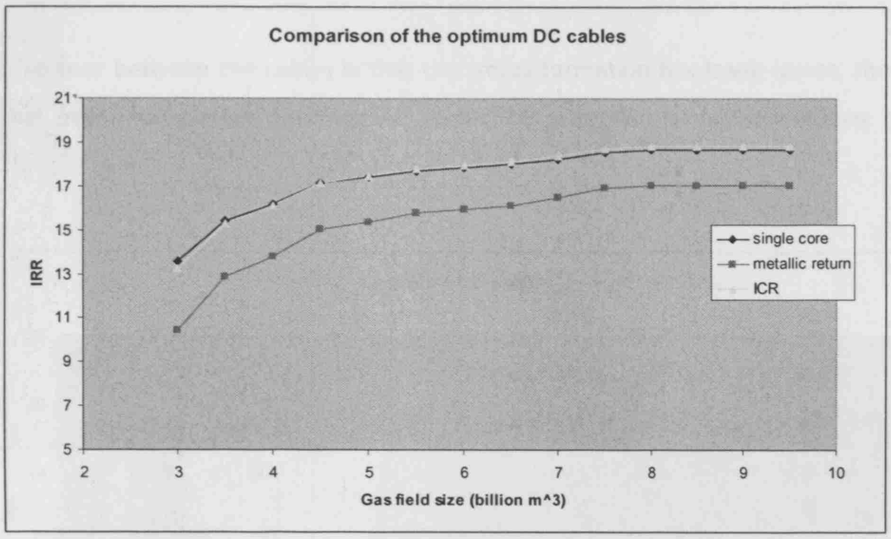


Figure 2 Optimum DC cable.

From the graph it can be concluded that metallic return cable has the lowest IRR and the lower losses of metallic return cables do not offset the lower cost of the cheaper but not so efficient single core and ICR cables.

This analysis results in the metallic return cable being eliminated from the above comparison, unless the increased power generation capacity offered by this cable is taken into account for longer investment. On the other hand the selection between single core and ICR is a close call and is dependent on the size of the gas field. Possible corrosion effects of the electrodes associated with the single core cable give an advantage to the ICR cable. It is therefore suggested that according to the present data comparison the ICR is the optimum DC cable for the project.

Optimum HVAC Cable Design

The optimum cables for Trefoil and Flat formation were analysed by using the cost model for a direct comparison at a base distance of 75 km and for a range of general gas field sizes as can be seen in the DC comparison. The two optimum cables that were imported to the economic model have the following characteristics:

Formation option	Voltage (kV)	Conductor Material	CSA (mm^2)	Cost (£/m)	Losses (MW/km)	Reduction* (%)
Flat	230	copper	500	472	0.1075	5.14
Trefoil	230	copper	500	472	0.0969	5.14

*Percentage of the reduction of power transmission based at 250MW and 75km transmission length

Table 2: Optimum AC cables

The only difference between the cables is that the trefoil formation has lower losses, therefore it is expected that trefoil will be the optimum AC cable. This is proven from the following cost model results:

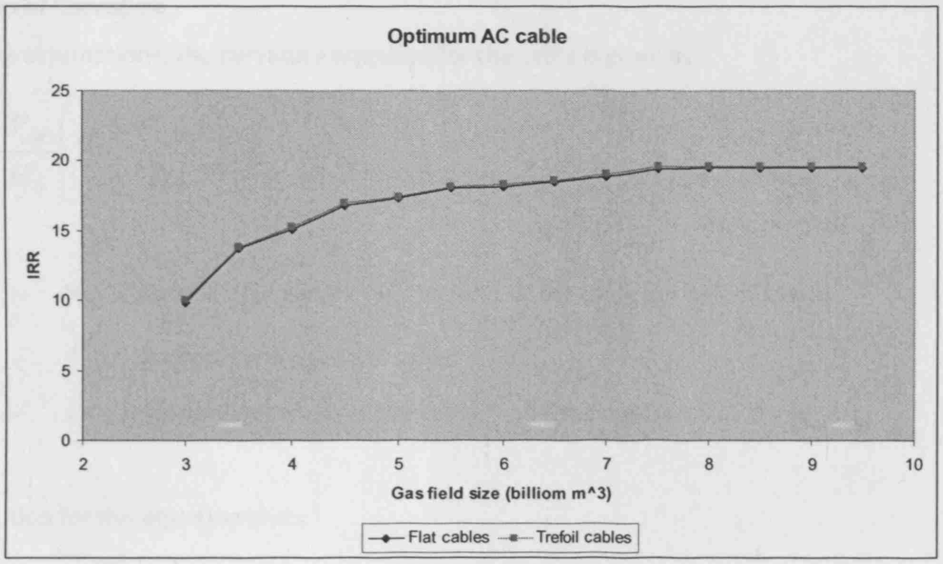


Figure 3 Optimum AC cable

From the graph it can seen that Trefoil has higher IRR across the range of different gas field sizes. It should be noted that the results are based upon provisional cable designs, sensitive cost data and multiples. It was also found out that a reduction of voltage to 110kV is possible and this will offer lower the CAPEX for AC cables. The trefoil cable will now be compared with the optimum DC cable.

Appendix 5

Static and Quasi-Static Analyses

Assumptions for the Analysis

The simple catenary theory is used to define the geometric configuration of the flexible riser by assuming:

- The bending stresses are ignored for the first approximation.
- The effects of the axial elongations are ignored
- The pressure and the drag forces on the cable are ignored.
- The lay angle of the cable with the seabed is null.

Equation of Curvature

From the assumptions, the curvature equation for the cable is given as:

$$\frac{d\theta}{ds} = \frac{W_{eff}}{H_0}\left(1 + \left[\frac{W_{eff}.s}{H_0}\right]^2\right)^{-1} \qquad [1]$$

where:

- W_{eff} is the effective weight (wet weight) of the cable per unit of length.
- H_0 is the axial tension in the cable.
- s is the suspended length of the cable from the origin (s = 0 at $x = x_{TDP}$).

The solution for this equation gives:

$$\theta(s) = \tan^{-1}\left(\frac{W_{eff}.s}{H_0}\right)$$

Length of the cable

By integration of equation [1], the suspended length of the cable is given as:

$$s(x) = \frac{H_0}{W_{eff}}\sinh\left(\frac{W_{eff}.\bar{x}}{H_0}\right) \qquad [2]$$

where $\bar{x} = x - x_{TDP}$.

Therefore, it can be seen that for $x = x_{TDP}$, $s = 0$. The total length, S of the cable can be obtained for $x = 0$.

Profile of the Cable

The profile of the cable in the Cartesian axis is calculated by using the method introduced by Moe and Amsten[1]. The profile is:

$$z = \frac{H_0}{W_{eff}}\left[\cosh\left(\frac{W_{eff}.\bar{x}}{H_0}\right) - 1\right] \quad [3]$$

Modified Catenary Curvature Equation

The solution for the curvature was obtained by neglecting the bending stiffness effects. However, this effect cannot be ignored in the vicinity of the TDP due to the curving of the cable near the TDP. Therefore, the curvature equation has to be modified. The introduction of the bending stiffness by a boundary layer approach and the following modified equation is then obtained:

$$\chi_{0,f}(s) = H(s+\lambda)\left(1 - e^{-\left(\frac{s+\lambda}{\lambda}\right)}\right)\chi_0 \quad [4]$$

where:

- H is the Heaviside function (a switch function).
- χ_0 is the first curvature equation [1] near the touchdown point.
- λ is the flexural length.

4.6.4 Determination of the Stiffness

Calculation of Axial Stiffness

By considering the axial loads acting upon a cross section, the axial stiffness *EA* of an element *i* of the cable riser is given by:

$$EA_i = n.E.A.\cos\theta\left(\cos^2\theta - v\sin^2\theta\right) \quad [5]$$

where:

- *n* is number of strips
- *E* is Elasticity modulus

[1] G Moe and O Arnsten, *An Analytical Model for Static Analysis of Catenary Risers*, Proceedings of the Eleventh International Offshore and Polar Engineering Conference, Trondhein, Norway, Vol. 2, pp 248 – 253.

- A is cross sectional area of the element
- v is poisson ratio
- ϑ is the lay angle of the strip

Expression [5] can be used for classic elements, not constituted of strips e.g. the core. When n = 1 and ϑ = 0 then the efficient axial stiffness becomes:

$$EA_i = E.A \qquad [6]$$

It can be noted that the total axial stiffness of the flexible riser can be obtained by summing all the axial stiffnesses:

$$EA_{effective} = \sum_{i=1}^{N} E_i.A_i + \sum_{i=1}^{m_l} \left(\cos^2\theta_i - v\sin^2\theta_i\right) n_i.E_i.A_i.\cos\theta_i \qquad [7]$$

where N is the number of material layers which constitute the core and m_l the number of other layers.

Calculation of Bending Stiffness

Costello suggested the following expression originally derived by Timoshenko[2] for the calculation of the bending stiffness:

$$EI = \frac{E\pi R^4 2m\sin\beta}{4\left(2 + v\cos^2\beta\right)} \qquad [8]$$

where:

- m is the number of wires
- R is the radius of the individual wire
- $\beta = \frac{\pi}{2} - \theta$ is the helix angle

As for the previous axial stiffness, the bending stiffness for the core can be calculated by [8], if m = 1 and ϑ = 0 then [8] becomes:

$$EI = \frac{E\pi R^4}{4} = E.I \qquad [9]$$

where I is the second moment of the area.

Therefore, the total bending stiffness for the flexible riser becomes:

$$EI_{effective} = \sum_{i=1}^{S} \frac{E_i\pi R_i^4 2m_i \sin\beta_i}{4\left(2 + v_i\cos^2\beta_i\right)} + \sum_{i=1}^{N} E_i I_i \qquad [10]$$

[2] GA Costello, *Stress in Multilayered Cables,* Journal of Energy Resources Technology, Vol. 105, pp 521-524, 1983.

Calculation of Tension

Horizontal Component of the Tension in the Cable

For a cable forming a simple catenary resting on the seabed at $(x_{TDP}, 0)$, but being held at the top end of a vessel at $(0, z_t)$, the equation of the profile is give by equation [3]. If equation [3] is applied in the point TE, (0, h), the expression becomes:

$$\cosh\left(\frac{-Weff.x_{TDP}}{H_0}\right) - 1 - \frac{h.Weff}{H_0} = 0 \qquad [11]$$

Therefore, it is possible to determine value of H_o for a fixed value of water depth and a position for the touch down point.

Effective Tension in the Cable

It is assumed by E. T. Etuk in [1] with the previous hypotheses that the effective tension in the cable is:

$$T(s) = H_0\left(1 + \left(\frac{Weff.s}{H_0}\right)^2\right)^{\frac{1}{2}} \qquad [12]$$

Equation [2] then allows the calculation of the effective tension in function of x:

$$T(x) = H_0\left(1 + \sinh^2\left(\frac{Weff.x}{H_0}\right)\right)^{\frac{1}{2}} \qquad [13]$$

Axial Tension/Stress

The axial tension at any point along the cable riser will be shared by the conductor and the armoring wires. The tension taken up by the constituents of the cables is directly proportional to the axial stiffness of the component members, giving

$$Tc_i = T(s)\frac{EA_{ci}}{EA_{effective}} \qquad [14]$$

where:

- *Tci* is the tension taken up by the *ith* material of the core
- *T(s)* is the axial tension along the length of the cable
- $EA_{effective}$ is the total effective axial stiffness of the riser
- EA_{ci} is the axial stiffness of the *ith* material of the core

The following axial tensions can be determined:

- The axial tension along the cable
- The axial tension in the core along the length of the cable

- The axial tension taken up by the armouring layer

Bending Stress

The maximum bending stress of the core is obtained by a modification of:

$$\sigma_b = \frac{M.y}{I} \qquad [15]$$

where:

- σ_b is the bending stress.
- *M* is the bending moment.
- *y* is the maximum distance from the neutral axis.
- *I* is the second moment of the area of the core.

The bending moment (M) is given by the basic Euler beam theory, modified by the catenary curvature equation [4]. This becomes:

$$M = EI_{eff}\left[H(s+\lambda)\left(1-e^{-\left(\frac{s+\lambda}{\lambda}\right)}\right)\chi_0(s)\right] \qquad [16]$$

where EI_{eff} is the effective bending stress of the core.

Now we can write the expression of the bending stresses for the conductor, if it is assumed that the cable neutral axis passes through the centre:

$$\sigma_b = \frac{EI_{eff}.R}{I}\left[H(s+\lambda)\left(1-e^{-\left(\frac{s+\lambda}{\lambda}\right)}\right)\frac{w.s}{H}\left(1+\left[\frac{w.s}{H}\right]^2\right)^{-1}\right] \qquad [17]$$

It can be noted that this expression for the bending stresses is just satisfactory at the vicinity of the touchdown since that the bending stresses are not considered for the rest of the cable. Nevertheless, equation [17] can be used for the whole cable as it shows significant value for bending stress after the touchdown point.

The Limiting Values of the Static Analysis

Theory

In order to obtain more accurate values, Etuk introduced different values of TE, called offset for the static case. These values refer to distances from the original static point given by a percentage of the water depth.

These two new static positions allow limit values for the studied static configuration.

New Top End Tension

The new static positions are linked with the previous static position thanks to the horizontal top end tension. From equation [1], the new value of the horizontal top end tension at the offset is:

$$H_{offset} = T_{eff}(top) - W_{eff} * h - T_{eff}(top) * \frac{offset}{\sqrt{offset^2 + h^2}} \qquad [18]$$

where:

- $T_{eff}(top)$ represents the effective tension at the top end point for the initial static configuration.
- offset represents the distance from the original static touch end point.
- h is the water depth
- Weff is the effective weight.

Therefore with a new horizontal top end tension, a new X_{TDP} can be calculated using the catenary solutions:

$$x_{TDP} = -\left(\frac{H_{offset}}{W_{eff}}\right) * \cosh^{-1}\left(W_{eff} * \frac{h}{H_{offset}} + 1\right) \qquad [19]$$

Then with a new X_{TDP} and the new horizontal top tension, all the parameters are given to calculate stresses from the previous static equations.

Offset Values

To apply this method, some offset has to be defined. As it was mentioned earlier, the offset for the static analysis is given by a percentage of the water depth. These values are:

- $\pm 5\%$ of the water depth
- $\pm 10\%$ of the water depth

Appendix 6

Matlab Code for Static Analysis

```
MECHANICAL ANALISYS OF A RISER

% June 2006
% version : 1.5
% Last modification : 26th July 2006

%Function employed :
%     - Stiffness --> Calculate the effective stiffness
%     - h_comp --> Calculate the horizontal component of the tension in the cable
%     - Effective_Tension -> calculate the effective tension in the cable
%     - Heaviside function
%     - static function

clear all;
close all;

%% DEFINITION OF THE PARAMETERS

%------------------------ Fixed Values -------------------------%

%density of the sea water in Kilo per cube meters (Kg/m^3)
pw = 1025;

%Acceleration due to the gravity in Kilo per squre seconds (Kg/s^2)
gv = 9.81;

% water depth in meter (m)
wd = input('enter a value of water depth:\');

%value of the xtdp
xtdp = input('enter a value for the touchdown point:\');

%---------------------- Global Variables ---------------------%
```

```
% ----------- Material type : COPPER

% Outer diameter of cable in meter (m)
D = 0.138;

% Calculation of the cable cross sectional area :
Ao = D^2 * pi / 4;

% cable mass per length (Kg/m)
Wt_ca = 52.64;

% Calculation of the effective weight per unitlength (N/m)
Weff = Wt_ca * gv - (pw * gv * Ao);

%% CALCULATION OF THE STIFFNESS

% Calculation of the Stiffness%

Stiffness; %call of the application to calculate the stiffness
%this application returns:
%  - A vector with all the axial stiffness of each components of the cable -> A_S
%  - A vector with all the bending stiffness of each components of the cable -> B_S

%Structures of the vectors A_S and B_S:
%[solid_conductor_center layer_1_conductor_center layer_2_conductor_center
    layer_3_conductor_center layer_4_conductor_center
%    layer_1_outer_conductor    layer_2_outer_conductor    Mind_Insulation    Lead_sheath
    Polyethylene_Sheath Outer_XPE Galvanised_steel_armouring_layers]

%ratio between the axial stiffness of the core and the effective axial stiffness
Fcore = sum(A_S(1:7)) ./ sum(A_S);

% ratio between tha axial stiffness of the armour and the effective axial stiffness
Farm = A_S(12) ./ sum(A_S);

% Bending parameters %

%for the core
```

```
% the model is based on the Costello model
%the bending stresses are calculated for an area of 25% of the xtdp value around the TDP

%Diameter of the core in meters (m):
Dcoreint = 0.044; %inner diameter in meters (m)
Dcoreouti = 0.1; %inner diameter of the outer core in meters (m)
Dcoreouto = 0.1192; %outer diameter of the outer conductor in meters (m)

Dcore = Dcoreint + Dcoreouto - Dcoreouti; %Effective Diameter of the both conductors in meter (m)

%Second moment of the area
Icore = pi .* Dcoreint.^4 ./ 64 + pi .* (Dcoreouto.^4 - Dcoreouti.^4) ./ 64;


%% STATIC OF THE RISER

% CALCULATION OF THE HORIZONTAL TENSIONS %

% horizontal tension for the defined static position
H = h_comp(Weff, xtdp, wd);

%------------------------------------------- the cable profile -------------------------------------------------%
% points of the Cartesian axis
X = [xtdp:-xtdp / 1000 :0];
Z = (H ./ Weff) .* (cosh(Weff .* (X - xtdp) ./ H) - 1);

%curvilinear distance on the cable
s = (H ./ Weff) .* sinh(Weff .* (X - xtdp) ./ H);

%Calculation of the effective tension%

Teff = Effective_Tension(H, Weff, xtdp, s);

% Bending stresses%

%Calculation of the flexural length of the core
l= sqrt(sum(B_S(1:7)) ./ Teff(end));
```

```
%modified curvilinear equation
%1/4 of xtdp value aroud the xtdp point
d = round(abs(xtdp./4));

Xm = [-50 + xtdp : -(-50 +xtdp) ./ 500 : 0];

sm = (H ./ Weff) .* sinh(Weff .* (Xm - xtdp) ./ H);

Sm = Heaviside(sm + l) .* (1 - exp(-(sm + l) ./ l)) .* (Weff .* sm ./ H) .* (1 + (Weff .*sm ./ H).^2).^-1;

%Bending stress of the core

Sb = sum(B_S) .* Dcore ./ (2 .* Icore) .* Sm;

clear l d H xtdp;
```

```
%%------------------------------------------OFFSET--------------------------------------------%

% July 2006
% version : 1.1
% Last modification : 26th July 2006

% This program calculate limit values for the static study of a riser
% Used function :
%   - Mech: subroutine which calculates a static profile

Mech

%---------------------- Limit values for the static ------------------------------------------%

% Offset is apply to obtain some limit values foe the static position.
% Offset is defined as a pourcentage of water depth.

Offset = [0.05 .* wd, -0.05 .* wd, 0.1 .* wd, -0.1 .* wd];

for i = 1 : length(Offset)

  %Calculation of the new horizontal top tension
  H_offset = Teff(end) - (Weff .* wd) + Teff(end) .* (Offset(i) ./ ((Offset(i).^2 + wd.^2).^0.5));

  % Calculation of the new xtdp
  xtdp_offset = -(H_offset ./ Weff) .* acosh((Weff .* wd ./ H_offset) + 1);

  % points of the Cartesian axis
  X_offset(i,:) = [xtdp_offset: -xtdp_offset / 1000 :0];
  Z_offset(i,:) = (H_offset ./ Weff) * (cosh(Weff .* (X_offset(i,:) - xtdp_offset) / H_offset) - 1);

  %curvilinear distance on the cable
  s_offset(i,:) = (H_offset ./ Weff) .* sinh(Weff .* (X_offset(i,:) - xtdp_offset) ./ H_offset);

  Teff_offset(i,:) = Effective_Tension(H_offset, Weff, xtdp_offset, s_offset(i,:));

  %Bending stresses
  %Calculation of the flexural length of the core
  lambda = sqrt(sum(B_S(1:7)) ./ Teff_offset(i,end));

  %modified curvilinear equation
  %1/4 of xtdp value aroud the xtdp point
  d = round(abs(xtdp_offset ./ 4));

  Xm_offset(i,:) = [-50 + xtdp_offset : -(-50 + xtdp_offset) ./ 500 : 0];

  sm_offset(i,:) = (H_offset ./ Weff) .* sinh(Weff .* (Xm_offset(i,:) - xtdp_offset) ./ H_offset);

  Sm_offset(i,:) = Heaviside(sm_offset(i,:) + lambda) .* (1 - exp(-(sm_offset(i,:) + lambda) ./
lambda)) .* (Weff .* sm_offset(i,:) ./ H_offset) .* (1 + (Weff .* sm_offset(i,:) ./ H_offset).^2).^-1;

  %Bending stress of the core

  Sb_offset(i,:) = sum(B_S) .* Dcore ./ (2 .* Icore) .* Sm_offset(i,:);

  clear H_offset xtdp_offset lambda;
end
```

Appendix 7

Matlab Code for Quasi-Static Analysis

2ND ORDER MOTION

```
% July 2006
% version : 1.1
% Last modification : 26th July 2006

% This program calculates the 2dn motion order of a riser.
% Used function / subroutines:
%      - Mech : subroutine which calculates the static parameters


Mech

% ---------------- Definition of the sea states parameters -------------------------------%

% the different sea states create 2 different offsets, which are given in meters
% The sea states parameters are defined in a matrix : each colomn represents a sea state
% The first row represents the Near-Near position to the anchor point
% The second row represents the Near-far position to the anchor point

% These offsets create new static configuration.

SEA = [-9 -20 -31 -42 -52 -62
    -3 -2 -4 -6 -8 -8];


for i = 1:size(SEA,1)
  for j = 1:size(SEA,2)
    %Calculation of the new horizontal top tension
    H_sea = Teff(end) - (Weff .* wd) + Teff(end) .* (SEA(i,j) ./ ((SEA(i,j).^2 + wd.^2).^0.5));

    % Calculation of the new xtdp
    xtdp_sea = -(H_sea ./ Weff) .* acosh((Weff .* wd ./ H_sea) + 1);

    % points of the Cartesian axis
    X_sea{i,j} = [xtdp_sea: -xtdp_sea / 1000 :0];
    Z_sea{i,j} = (H_sea ./ Weff) * (cosh(Weff .* (X_sea{i,j} - xtdp_sea) / H_sea) - 1);

    %curvilinear distance on the cable
    s_sea{i,j} = (H_sea ./ Weff) .* sinh(Weff .* (X_sea{i,j} - xtdp_sea) ./ H_sea);

    Teff_sea{i,j} = Effective_Tension(H_sea, Weff, xtdp_sea, s_sea{i,j});

    %Bending stresses
    %Calculation of the flexural length of the core
    lambda = sqrt(sum(B_S(1:7)) ./ Teff_sea{i,j}(end));

    %modified curvilinear equation
    %1/4 of xtdp value aroud the xtdp point
    d = round(abs(xtdp_sea ./ 4));
```

```
    Xm_sea{i,j} = [-50 + xtdp_sea : -(-50 + xtdp_sea) ./ 500 : 0];

    sm_sea{i,j} = (H_sea ./ Weff) .* sinh(Weff .* (Xm_sea{i,j} - xtdp_sea) ./ H_sea);

    Sm_sea{i,j} = Heaviside(sm_sea{i,j} + lambda) .* (1 - exp(-(sm_sea{i,j} + lambda) ./ lambda)) .*
(Weff .* sm_sea{i,j} ./ H_sea) .* (1 + (Weff .* sm_sea{i,j} ./ H_sea).^2).^-1;

    %Bending stress of the core

    Sb_sea{i,j} = sum(B_S) .* Dcore ./ (2 .* Icore) .* Sm_sea{i,j};

    clear H_sea xtdp_sea lambda d;
  end
end
```

Appendix 8

Initial Sizing

Initial Sizing

The objectives of initial sizing is to establish a model for the Base Case CEPV which will then be used in the sensitivity analysis of the vessel design in terms of size and cost given approximate estimates of the vessel components and systems. Estimation is obtained by scaling off of a similar type vessel, which in this case is based upon BP's FPSO Schiehallion.

Summary of Sample Calculations for First Iteration

The design of the Base Case CEPV is done by using a volume-driven approach rather than the conventional weight-driven approach. This is simply because the vast spaces occupied by onboard machinery e.g. CCGT Plant are actually weighing a lot less than a similar space occupied by cargo in a merchant vessel. Therefore, a warship type breakdown of group systems is used to obtain a breakdown of system components required for the CEPV. The breakdown used is shown below:

Group 1 – Hull
General
Navigation
Anchoring & Mooring
Structure
Outfit
Water Ballast

Group 2 – Personnel
Personnel Support
Accommodation

Group 3 – Ship Systems
Air-Conditioning & Ventilation
Sea & Fresh Water Systems
Waste Disposal System

Group 4 – Electric Propulsion
Electric Thrusters
Tunnel Thrusters
Bow Thrusters
Stern Thrusters

Group 5 – Electric [illegible]
Electric Power Distribution
Step-Up Transformers
Step – Down Transformers

Group 6 – Payload
Processing Deck
Submerged Turret Production
Gas turbine, steam turbine, WHRU and alternator
CO_2 Sequestration Plant
Miscellaneous

Group 7 – Variable
Stores
Diesel
Fresh Water
Miscellaneous

Tables 1 – 7 Groups of Systems and Components

Having obtained the group breakdown, the next step is to balance the model built into an Excel spreadsheet to ensure that the volume required is the same as the volume enclosed. For the first iteration the payload volume is used. The procedure involved is shown in Table 8. The total payload is the total of Group 6 volume plus the total of Group 7 volume. The table below gives the breakdown of the Groups 6 and 7 volumes.

Group 6 – Payload	Volume (m^3)	Weight (tonnes)
Processing Deck	28000	900
Submerged Turret Production	1400	5300
Gas turbine, steam turbine, WHRU and alternator	10020.96	2697.4
CO_2 Sequestration Plant	6090	1999.28
Miscellaneous	5184	180
Variables	Volume (m^3)	Weight (tonnes)
Stores	200	2.62
Diesel	4000	3600
Fresh Water	386	386
Miscellaneous	121	159.58

Note: Stores were calculated assuming a complement of 20 men and for storage of 30 days.

Table 8 Group 6 and 7 volumes

Assuming a payload volume fraction, *pvf* of 0.8 (for tankers) it is then possible to calculate the total enclosed volume.

$W_{payl.} + W_{var.}$ = Payload weight

$V_{payl} + V_{var.}$ = Payload volume

pvf = 0.8

$$\text{Total enclosed volume} = \frac{\text{Payload volume}}{pvf}$$

$$= \frac{55221}{0.8}$$

$\therefore$ Total enclosed volume = 69,026 m^3

It is now possible to calculate the initial estimate of deep displacement.

Deep Displacement = $\Delta = \rho V$

Where the density referred to here is the overall density. For a tanker this is approximately 0.75.

∴ Deep Displacement = 0.75 x 69,026

∴ Deep Displacement = 51,770 tonnes

It was now necessary to assume form parameters for above water and underwater forms. Typical values for crude oil tankers are used.

$C_B = 0.85$

$C_P = 0.94$

$K_B = 2.25 = B / T$

$C_M = 0.9 = C_B / C_P$

$v_S = 0.05$

Minimum depth to accommodate machinery plus double bottom plus allowance for cable ducting gave a depth of approximately 19 m.
After balancing the spreadsheet this yielded having a vessel dimension of:

D = 19 m

L = 145 m

B = 27.5 m

T = 14.91 m

Freeboard = 4.09 m

The Group systems were slightly modified to accommodate these changes and the new changes are tabulated in the next section. Groups 1 to 5 remained the same and therefore only the groups which have been changed are given. These changes are shown in Tables 9 and 10.

Group 6 – Payload
Processing Deck
Submerged Turret Production
Gas Turbines, Generators & WHRU
Steam Turbines and generators
CO_2 Sequestration Plant

Group 7 – Variables
Stores
Diesel
Fresh Water
Condensate
Crude Oil

Tables 9 and 10 Group 6 and 7 – Modified Systems

With the requirements for storage of both condensate and crude oil, and with the need to accommodate the equipment the dimensions obtained in the first iteration was found to be unfeasible, and therefore the vessel had to be resized.

The pie charts in Figures 1 and 2 show the breakdown of group weights and volumes for the Base Case CEPV.

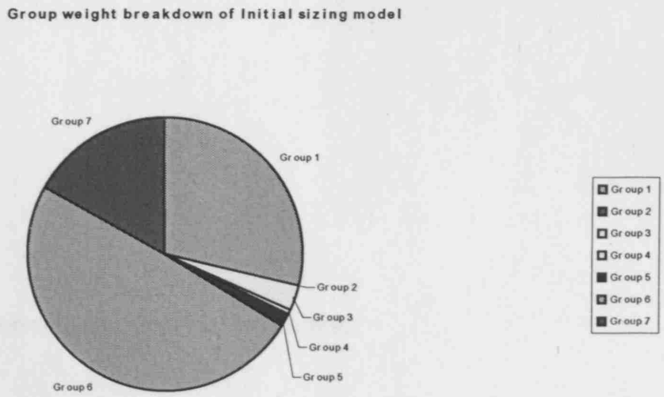


Figure 1 Group Weight Breakdown of Initial Sizing Model

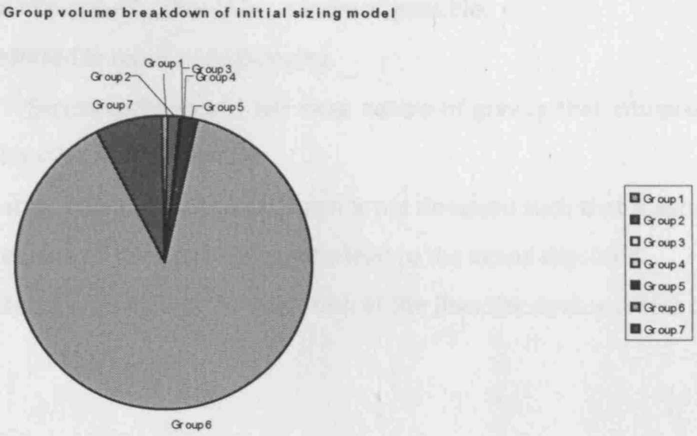


Figure 2 Group Volume Breakdown of Initial Sizing Model

Appendix 9

Parametric Survey

The objectives of the parametric survey are:

- To optimise the seakeeping performance of the vessel
- To optimise the draught and freeboard, in order to minimise slamming and green water on deck.
- To explore options of generating power output chosen, in terms of gas turbine selection.

For good seakeeping characteristics the forward body of the ship is crucial, since it can lead to problems with pitching, rolling and sway effects. The important parameters for achieving good seakeeping characteristics are;

- C_W
- C_B
- The section shape
- Above water form

Typical effects of dimensions upon seakeeping performance are;

- Length – increase in length reduces pitch and heave motions in head seas.
- Beam – high beam could lead to bad roll accelerations, but can also give good Seakeeping characteristics in beam seas.
- Draught – vessel must meet the required limits for freeboard for safety of life at sea.
- Water-plane area coefficient – C_W should be as large as possible.
- K_B –high value is preferred in terms of Seakeeping.
- Above water form – Excessive freeboard will raise centre of gravity that compromises stability and vessel handling due to windage.
- Bulwarks – care must be taken to make sure that it is not designed such that it allows for too much water retention which can consequently lead to the vessel capsizing.
- Bow shape – by having a low value of the extension at the bow the deck wetness can be decreased.

In this design the aim of the parametric survey is to yield an optimum arrangement in terms of the means of generating the power output of approximately 264 MW required. Having chosen the gas turbines and steam turbines for electrical power generation and the general layout, the hull form will be selected to ensure good seakeeping characteristics of the vessel.

With the need to explore the different means of generation of 250 MW, the parametric survey was used to explore the viable options. The calculations for estimating the size of these options are shown below. These functions were given as;

For the Gas turbines, generators and heat recovery

$$W = 25 + 7.45P_1$$

For the Steam turbines and generators

$$W = 50 + 7.14P_1$$

Where P_1 is the Gas turbine output in megawatts

<u>OPTION 1</u>

4 Gas turbines and 2 Steam turbines

Gas turbine dimensions = 32.55m x 8.996m x 10m
Steam turbine dimensions = 16.5m x 7m x 10.5m
Gas turbine output = 63 MW
W_{GT} = 25 + 7.45 x 63 = 494.35 tonnes
W_{ST} = 50 + 7.14 x 63 = 499.82 tonnes
Envelope required to fit turbines is given by;
Length = 2 x 32.55 + 16.5 +1+1+1+1 =85.6 m
Length (Processing plant) = 50 m
Length (Electrical distribution room) = 20
Length of Bow section from processing plant = 30 m
Total length required = 185.6 m
Beam is governed by footprint required on the main deck for the processing plant
Beam = 27 +1.5+1.5 = 30 m
Depth is governed by height of equipment plus double bottom plus area for electrical distribution cables.
Depth = 10.5+2+2.5 = 15.5 m

Making the changes in the sizing model and running it again to balance the ship yields us a vessel with the following dimensions.

Length = 188.72 m

Beam = 29.96 m

Depth = 16 m

Draught = 10.89 m

Freeboard = 5.11 m

Displacement = 53662.8 tonnes

<u>Option 2</u>

4 Gas turbines and 2 Steam turbines

Gas turbine dimensions = 32.55m x 8.996m x 10m

Steam turbine dimensions = 16.5m x 7m x 10.5m

Gas turbine output = 63 MW

W_{GT} = 25 + 7.45 x 63 = 494.35 tonnes

W_{ST} = 50 + 7.14 x 63 = 499.82 tonnes

Envelope required to fit turbines in is given by;

Length = 32.55 + 16.5 +1+1+1 =52.05 m

Length (Processing plant) = 50 m

Length (Electrical distribution room) = 20

Length of Bow section from processing plant = 30 m

Total length required = 152 m

Beam is governed by spread of gas turbines;

Beam = 8.996 x 4 + 2 + 2 +1+1+1 = 43 m

Depth is governed by height of equipment plus double bottom plus area for electrical distribution cables.

Depth = 10.5+2+2.5 = 15.5 m

Making the changes in the sizing model and running it again to balance the ship yields us a vessel with the following dimensions.

Length = 150 m

Beam = 45 m

Depth = 15 m

Draught = 9.74 m

Freeboard = 5.26 m

Displacement = 56883 tonnes

OPTION 3

2 Gas turbine s and 2 Steam turbines

Gas turbine dimensions = 52m x 17.3m x 16m

Steam turbine dimensions = 17.3m x 12m x 11m

Gas turbine output = 160.7 MW

W_{GT} = 25 + 7.45 x 160.7 = 1222.2 tonnes

W_{ST} = 50 + 7.14 x 160.7 = 1197.8 tonnes

Envelope required to fit turbines in is given by;

Length = 52 + 17.3 +1+2 =72.3 m

Length (Processing plant) = 50 m

Length (Electrical distribution room) = 20

Length of Bow section from processing plant = 30 m

Total length required = 172.3 m

Beam is governed by need to fit gas turbines in a parallel manner.

Beam = 16 x 2 + 1 +2 = 35 m

Depth is governed by height of equipment plus double bottom plus area for electrical distribution cables.

Depth = 16+2+2.5 = 20.5 m

Making the changes in the sizing model and running it again to balance the ship yields us a vessel with the following dimensions.

Length = 171 m

Beam = 34.5 m

Depth = 21 m

Draught = 13 m

Freeboard = 8 m

Displacement = 66983.5 tonnes

OPTION 4

1 Gas turbine and 1 Steam turbine

Plant footprint = 96.3m x 48m x 30m

Gas turbine output = 304.3 MW

W_{GT} = 25 + 7.45 x 304.3 = 2292 tonnes

W_{ST} = 50 + 7.14 x 304.3 = 2223 tonnes

Envelope required to fit turbines in is given by;

Length =96.3 m

Length (Processing plant) = 50 m

Length (Electrical distribution room) = 20

Length of Bow section from processing plant = 30 m

Total length required = 196.3 m

Beam is governed by need to fit the plant.

Beam = 48 m

Depth is governed by height of equipment plus double bottom plus area for electrical distribution cables.

Depth = 30+2+2.5 = 34.5 m

Making the changes in the sizing model and running it again to balance the ship yields us a vessel with the following dimensions.

Length = 197 m

Beam = 49 m

Depth = 34 m

Draught = 14.7 m

Freeboard = 19.3 m

Displacement = 123800tonnes

Parametric Survey Options

To produce an arrangement/layout suitable for the design of the Base Case CEPV a design methodology is used. This is because the design of a CEPV has not been done before. Therefore, there were no previous design templates, examples guidance notes or rules for design to follow.

The main issues are that the gas intake through the risers in the submerged turret production system should be kept as far away as possible in the interest of safety. Also, in terms of maintenance it is required that the gas processing plant on the main deck is to be kept far away from the power plant on the lower deck, i.e. not directly above.

Option 1

This option considers four gas turbine generating sets and two steam turbine generating sets, giving an output of 264 MW. This arrangement has resulted in a vessel with dimensions summarised in Table 1.

Option 1	
Length	188.72 m
Beam	29.96 m
Draught	10.89 m
Depth	16 m
Displacement	53,663 tonnes
Structural Weight	8,300 tonnes
Cost	£32.3 M

Table 1 Option 1

Option 2

This option considers the same four gas turbines and two steam turbines but in a different arrangement. This new arrangement now uses all the gas turbines in parallel and the two steam turbines are also arranged in parallel. This arrangement has resulted in a vessel with dimensions shown in Table 2.

Length	149.52 m
Beam	44.82 m
Draught	10.74 m
Depth	16 m
Displacement	56,883 tonnes
Structural Weight	8,697 tonnes
Cost	£35.2 M

Table 2 Option 2

Option 3

This option considers an arrangement of two gas turbines and two team turbines. These are bigger turbines compared to the ones considered in Options 1 and 2 but give an output of 270 MW. Both gas turbines and steam turbines are arranged in parallel with the steam turbines being fed directly by the gas turbines in series. This arrangement has resulted in a vessel with dimensions shown in Table 3.

[illegible]	[illegible]
Length	171.04 m
Beam	34.51 m
Draught	13.02 m
Depth	21 m
Displacement	66,984 tonnes
Structural Weight	9,327 tonnes
Cost	£34 M

Table 3 Option 3

Option 4

This option considers the arrangement of one gas turbine and one steam turbine. These are also much bigger than those used for option 3 and are arranged in a simple series type manner. It also generates an output of about 280 MW. This arrangement has resulted in a vessel with dimensions shown in Table 4.

[illegible]	[illegible]
Length	190.44 m
Beam	48.14 m
Draught	14.81 m
Depth	34 m
Displacement	118,294 tonnes
Structural Weight	18,070 tonnes
Cost	£53.7 M

Table 4 Option 4

Parametric survey option chosen

Criteria	Weight	Option 1		Option 2		Option 3		Option 4	
		Score	Weighted Score	Score	Weighted Score	Score	Weighted Score	Score	Weighted Score
Gas turbine redundancy	7	8	56	8	56	5	35	4	28
Vessel cost	6	8	48	6	36	7	42	5	30
Vessel weight	5	8	40	7	35	6	30	5	25
Seakeeping characteristics	8	7	56	5	40	6	48	4	32
Total Score			200		167		155		115

Table 5 Design Evaluation Matrix

The parametric survey yielded four options. Each of these options has their advantages and disadvantages. Option 4 uses just one gas turbine and one steam turbine therefore so in terms of redundancy this option is not a favourable option. Using an arrangement in Option 4 has also resulted in a very large vessel hence higher cost and structural weight.

Option 3 is a good option in terms of overall arrangement and size. However, this has resulted in a larger and heavier vessel than either Option 1 or 2. Therefore, this is not a favourable option.

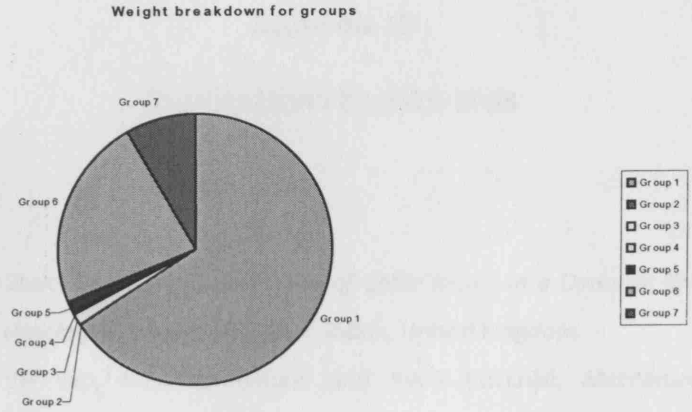
The best options are Options 1 and 2. This is simply because they have the least structural weight. These two options also addressed the issues of system redundancy with a four gas turbines and two steam turbines arrangement. Option 2 offered an option that really was very similar to box in that its L/B is approximately 3. This results in having a vessel that is likely to have very poor seakeeping characteristics, and is therefore likely to have increased pitch and heave accelerations. Therefore, Option 1 is chosen because it has the best overall performance and the least structural weight and cost.

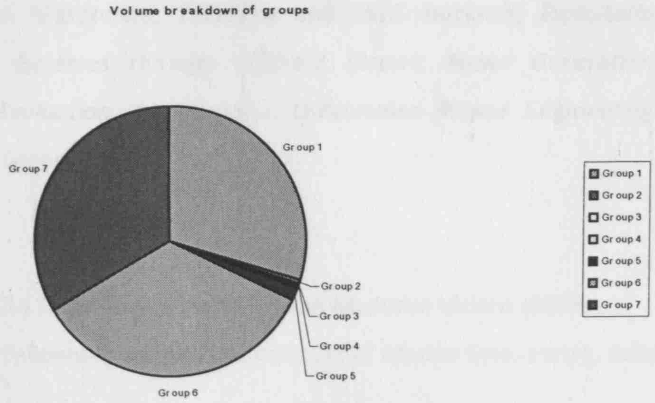
Summary

A minor modification is then made to the parametric survey results in order to obtain a vessel that has the principal dimensions and parameters similar to those of conventional FPSOs. This led to the following change in parameters as shown in Table 5. The pie charts shown in Figures 3 and 4 give the weight and volume breakdown for the Base Case CEPV following the results of the parametric survey.

[illegible]	[illegible]
Length	185.13 m
Beam	34.22 m
Draught	12.13 m
Depth	19 m
Freeboard	6.87
C_B	0.85
C_P	0.86
C_M	0.988
Displacement	66,981 tonnes
Structural Weight	10,133 tonnes
Cost	£34.5 M

Table 6 Chosen Options after Changes





Figures 1 and 2 Weight and Volume Breakdown for Groups

Appendix 10

Publications and Awards

Publications:

1. EH Yap and RWG Bucknall, *Performance of Cable Risers in a Dynamic Environment*, World Maritime Technology Conference 2006, London, United Kingdom.
2. CH Chien, EH Yap, HGA Martindale and RWG Bucknall, *Mechanical and Electrical Performance Analysis of High Power Subsea Transmission Cable,* International Universities Power Engineering Conference 2004, Bristol, United Kingdom.
3. EH Yap, HGA Martindale, T Zachos and RWG Bucknall, *Exploitation of Remote Area Hydrocarbon Reserves through Offshore Electric Power Generation: A Technical and Economical Evaluation,* International Universities Power Engineering Conference 2004, Thessaloniki, Greece.

Awards and Prizes:

1. First Prize, CESA Smart Award for European Maritime Visions (2007)
2. Stanley Gray Fellowship Award, The Institute of Marine Engineering, Science and Technology (2004)